on the road to success

Connacher Oil and Gas Limited · 2003 Annual Report

2003 highlights

* Revenue rose 131 percent; cash flow increased 220 percent; earnings were up 737 percent
* Cash flow per share doubled; earnings per share more than quadrupled
* Average daily production rose 74 percent year over year and more than quadrupled during the year
* Drilling activity was up 392 percent to 59 gross wells (57 net); all were cased
* Land base expanded to over 250,000 gross acres from only 55,000 acres in 2002
* Reserves more than tripled to 5.6 million equivalent barrels (proved and probable)
* Year end productive capacity set the stage for 2004 growth

Connacher Oil and Gas Limited is a Calgary–based exploration, development and production company. The company's principal assets are located in the Battrum and Cabri region of southwest Saskatchewan, where operatorship and 75 to 100 percent working interests are held in oil and natural gas production and in over 50,000 acres. A further 110,000 acres are controlled in the Tompkins and Claydon areas, also in southwest Saskatchewan. Other significant exploration and production interests are held at Islay, Alberta. Recently, Connacher also acquired a 100 percent working interest in two townships of oil sand leases at its Great Divide project area southwest of Fort McMurray, Alberta. Connacher also retains a 50 percent working interest in a 95,000 acre producing concession in Argentina.

In pursuing its objective of maximizing shareholder value, where possible Connacher secures large, operated interests. Over time, a balanced portfolio of oil and natural gas interests is being pursued. An opportunistic approach, supported by timely decisions, reflects management's experience and aggressive strategy towards realizing growth objectives.

Connacher Oil and Gas Limited

ANNUAL AND SPECIAL MEETING

3:00 p.m. (MDT)
Tuesday, May 11, 2004
Cardium Room
Calgary Petroleum Club
319 – 5th Avenue SW
Calgary, Alberta

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operating & financial highlights

	Year ended December 31		
	2003	2002	% Change
Financial ($)			
Total revenue	**9,982,291**	4,325,817	131
Cash flow from operations (1)	**3,352,778**	1,046,509	220
Per share, basic (1)	**0.10**	0.05	100
Per share, diluted (1)	**0.10**	0.05	100
Net earnings	**4,190,316**	500,720	737
Per share, basic	**0.13**	0.03	333
Per share, diluted	**0.12**	0.03	300
Capital expenditures	**35,769,867**	9,013,865	297
Shareholders' equity	**24,485,541**	5,279,336	364
Total assets	**49,669,077**	10,254,881	384
Operations			
Daily Production			
Oil and liquids (bbl/d)	**789**	340	132
Natural Gas (mcf/d)	**1,190**	1,365	(13)
Equivalent (boe/d) (2)	**987**	568	74
Proven and Probable Reserves (3,4)			
Oil and liquids (mbbls)	**4,148**	1,200	246
Natural Gas (mmcf)	**8,553**	3,368	154
Combined (mboe)	**5,574**	1,762	216
Selling price ($/boe)	**27.56**	20.64	34
Operating cost ($/boe)	**8.47**	7.85	8
Operating netback ($/boe)	**14.25**	10.15	40
Shares Outstanding (000)			
Weighted average			
basic	**32,362,110**	19,890,276	63
diluted	**35,333,124**	20,376,708	73
End of period			
issued	**45,902,925**	24,175,334	90
fully diluted	**53,717,070**	34,169,549	57

(1) Cash flow from operations and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by others.
(2) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1 bbl.
(3) Compared to established reserves (proved plus one-half probable) in 2002.
(4) 2003 reserves compiled based on National Instrument 51-101 (NI 51-101).

our aggressive 2003 drilling and land acquisition program has laid the foundation for

further growth

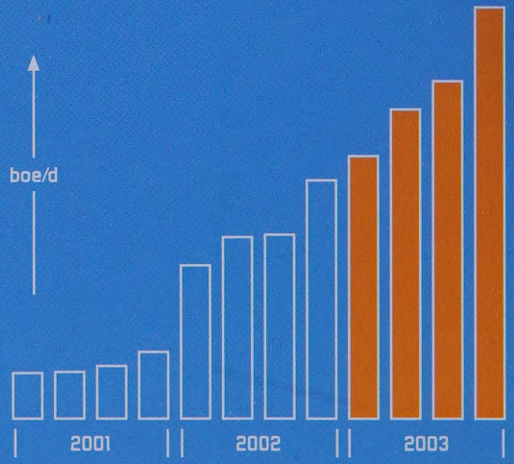
in 2004

Connacher drilled 59 gross wells during 2003.

Of the 34 natural gas wells Connacher now has on its North Block at Cabri, Saskatchewan, 26 were completed prior to year end and tied-in to market via TransGas with a planned rate of five mmcf/d. The remaining eight natural gas wells are now scheduled for tie-in to the system in the second quarter of 2004.

Ten farm-in wells at Tompkins, Saskatchewan have all been cased for evaluation of several hydrocarbon-bearing zones. Results are encouraging and earning is completed.

Through a workover and restimulation of one or more of the oil-bearing zones in the PMx1001 well Connacher hopes to improve Argentinian productivity in 2004. Additional drilling locations have been identified.

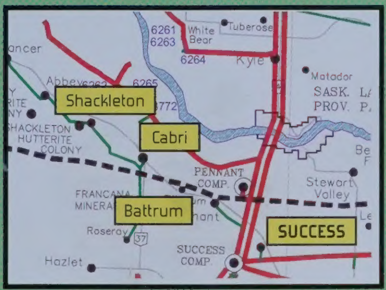


Production for the fourth quarter of 2003 averaged 1,228 boe/d.
December 2003 production was 1,442 boe/d.

Your company made great strides in 2003.

We are identifying hidden value on the "road to success" and as our broadened asset base brings about higher production, cash flow and earnings, share value should continue to appreciate.

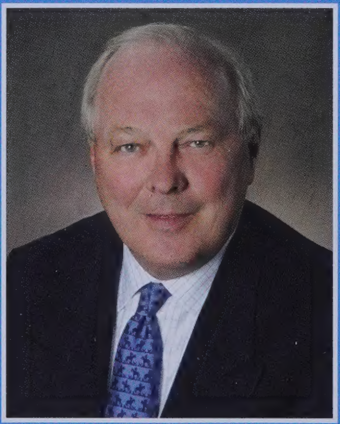
This remains our singular objective as we successfully apply our strategies.



Connacher charts its "Road to Success"

letter to shareholders

establishing our land position in the Shackleton Milk River natural gas play was a significant turning point...



Richard A. Gusella
President & Chief Executive Officer,
Connacher Oil and Gas Limited

our focus over the long term is increasingly on western Canada...

AN ACTIVE YEAR

Our activity level remained high throughout 2003. The early portion of the year was dominated by two acquisitions of producing oil properties at Battrum, Saskatchewan. Subsequently, we established our initial land position in the Shackleton Milk River natural gas play. This was a significant turning point for Connacher, as it established the company as a grass-roots explorer for natural gas. Investor interest in Connacher accelerated from this point forward. Buoyed by active trading and share price appreciation, we completed two equity placements during the year to help finance our growth expenditures.

As the year progressed, we expanded our land position at Battrum and Cabri. Connacher now owns and operates approximately 50,000 acres of prospective land in this core area. This was primarily accomplished through purchases at Saskatchewan crown sales. We continue to work towards consolidating and expanding this representation through third party farm-ins.

In addition to the establishment of these new core areas at Battrum and Cabri, we also secured two significant farm-ins within our southwest Saskatchewan focus region. These were completed with a major energy company and added over 40,000 acres of earnable petroleum and natural gas rights at Tompkins, Saskatchewan and over 70,000 acres at Claydon near the Canada/US border. These properties are prospective for shallow Cretaceous natural gas as well as deeper Jurassic natural gas and oil. They are easily-accessed, with available infrastructure to facilitate early production upon discovery. We are optimistic about our prospects in these areas. Connacher remains opportunity rich with a substantial inventory of drillable locations to fuel growth in 2004 and beyond.

Subsequent to year end we were also successful in acquiring a 100 percent working interest in over 50,000 acres of oil sand leases situated approximately 35 miles southwest of Fort McMurray, Alberta. These properties were posted for purchase by Connacher after review and study by management, which has considerable experience in this area of the oil and gas business. The acquired properties are judged to have tremendous productive and long-life reserves potential through the application of SAGD (steam-assisted gravity drainage) technology. Work is already underway to further evaluate these leases with a view to a rapid production start up, possibly as early as the fourth quarter of 2005. Financing alternatives to optimize the benefits to Connacher shareholders are also being reviewed and evaluated for this property.

BUILDING IN WESTERN CANADA

In just over two years, Connacher has transformed itself from a highly-speculative international exploration company to a well-established junior Canadian oil and natural gas company.

While we have retained our considerable exposure to the prospect of finding and developing large and profitable light oil reserves in Argentina, where we drilled a promising well in 2003, our focus over the long run is on western Canada. In that regard, we are well-positioned with a much-expanded land base of over 180,000 gross acres in natural gas-prone regions. We are also initiating a tertiary recovery pilot project at Battrum, which, if successful, could be translated into further opportunities. Finally, we have secured exposure to the remaining "big" oil in western Canada through our Great Divide project in the oil sands.

The challenge now is to realize our potential from these initiatives by converting assets into production, cash flow and earnings. This requires hard work, continued access to capital, solid technical initiatives, and dedicated people in the office and the field. I am pleased with the growing team we have put in place to accomplish our goals.

GROWTH IN 2003 RESULTS

Connacher made excellent progress in 2003. Our revenues more than doubled and cash flow from operations tripled while earnings, buoyed by recognition of a future tax asset, surpassed $4 million. Per share results demonstrated triple digit growth. Book equity approached $25 million compared to only $1.2 million two years ago. Total assets approached $50 million from $1.7 million in 2001.

Following eleven successive quarters of production growth averaging approximately 25 percent per quarter, Connacher's production averaged 987 boe/d in 2003. This is a year-over-year increase of 74 percent. We exited the year with surplus productive capacity as our new Cabri gas plant, which came onstream on December 21, 2003, only contributed sales volumes for a few days before year end. This established the basis for continuing production growth in 2004, not only from Cabri, but from other successes at Tompkins and Islay, which made minimal or no contribution to production prior to year end.

Prices were resolute throughout 2003. West Texas Intermediate Crude (WTI) averaged US $31.12 in 2003, an increase of 19 percent over 2002. AECO spot prices for Canadian natural gas averaged $6.79 per mcf in 2003, up 62 percent from the prior year. Our revenue per barrel of oil equivalent rose 34 percent to $27.56 despite continued weak Argentinian natural gas pricing. Timely hedges covering a portion of our heavy and medium-gravity crude oil production contributed positively to these higher realizations. Our efficiency, as measured by our field netback, also improved despite a significant rise in royalties per boe. The netback improvement reflects our improved product mix, as we lightened the composition of our production, shifting towards more natural gas and light oil production. Also, controllable unit cash costs, namely overhead and operating expenses, both declined sharply as a percentage of revenue. We will continue our commitment to be an efficient, low-cost operator.

During 2003 we drilled a record 59 wells (57 net) compared to only 12 last year. We also acquired three natural gas wells at Cabri in additional to numerous wells at Battrum. Our major areas of activity included Cabri (36 gross and 36 net wells) and Battrum (11 gross, 9 net wells). Discoveries during the year combined with the early–year acquisition of reserves and production at Battrum resulted in the 2003 addition of 1.9 million barrels of oil equivalent on a proved basis and 4.2 million barrels oil equivalent on a proved plus probable basis. As a result, Connacher replaced 536 percent of its 2003 production on a proved basis and 1,159 percent on a proved plus probable basis. New proved and probable reserves were added at a corporate average cost of $8.47 per boe. This results in a recycle ratio of 1.7 times, an acceptable level. Our reserve life index is 12.4 years based on fourth quarter production.

As is often the case for rapidly growing junior oil and gas companies, not every goal set out by Connacher was achieved in 2003. The company learned there are also potholes on the road to success. We did not reach our year-end exit production target due to disappointing Battrum results once the wells were tested, and because of startup problems at Cabri due to weather and mechanical issues. This has set us back heading into a new year and will cause us to reduce our 2004 expectations. Nevertheless, the push to succeed produced commendable results in 2003 and we still expect to achieve respectable growth in 2004.

SHARE APPRECIATION

Connacher's shares were well regarded in capital markets in 2003, rising 272 percent. On August 1, 2003 Connacher graduated to the Toronto Stock Exchange and subsequently stock market liquidity improved. Over 39 million shares traded in 2003. Two successful equity financings were accomplished during the year including a December 2003 bought-deal private placement of common shares, at favorable prices, for gross proceeds of $10.4 million. The company's liquidity remained healthy throughout the year, with Connacher's credit capacity rising from $5 million at December 31, 2002 to $31.5 million at year-end 2003. This reflects the increasing value of Connacher's Canadian revenue-generating assets and we maintained considerable unused credit capacity throughout the year. Our objective is to operate with a net debt to current cash flow ratio of 1.5 times or less.

OUTLOOK

Connacher's outlook remains positive despite lowered expectations as we anticipate continued strong commodity prices throughout 2004. Higher netback natural gas, which only contributed 20 percent of production in 2003, is targeted to rise in 2004. We anticipate a continued active drilling program with attendant production growth.

Most of our planned capital spending is discretionary. We expect to increasingly finance our capital outlays with cash flow as new production is placed on stream. This will be supplemented by disciplined borrowings and modest additional equity. Any new opportunities we might identify and wish to pursue will require additional permanent capital. As our inventory of plays and opportunities is plentiful at this juncture, it is unlikely we will take on many additional commitments in new regions, although we expect to continue our efforts to consolidate our holdings and dominate in our core areas if opportunities present themselves. This is consistent with our operational strategy, exemplified by our focused expansion in the Battrum and Cabri areas, of securing a high working interest and operatorship where possible.

We built aggressive targets in our original 2004 financial plan and budget, even though we have now scaled back our original expectations. Our drilling program will continue to be characterized by low-risk opportunities which can be replicated to accelerate our production, cash flow and earnings growth. We also emphasize plays with multiple objectives and significant infill development potential. This assures us an element of sustainability at lower risk. As in prior years, we will review our quarterly results and modify our plans appropriately. We cannot guarantee we will realize all of our goals and objectives, but you are assured we will be aiming to beat them. We hope thereby to ensure your continuing support as shareholders.

THANKS TO THE TEAM

Connacher's team is growing and adjusting as we increase the company's size and activity levels. Subsequent to year end Mr. Paul Jespersen resigned as Chief Operating Officer. This was done for personal reasons. He will continue to be available to Connacher as a part-time advisor and will focus his efforts on unlocking the value in both our Argentinian and oil sands properties. Paul's daily presence will be missed but we are fortunate to be able to continue our association in a redefined relationship. In February 2004 we announced the appointment of Mr. Peter D. Sametz to the position of Vice President, Operations. Peter brings a wealth of experience and expertise to the position and we welcome him as he assumes the day-to-day responsibilities of overseeing the company's operations.

During 2003 we appointed Mr. Songning Shen to the position of Exploration Manager, Mr. Tim O'Rourke was named General Manager, Production and Mr. Rick Kines became our Chief Financial Officer. We congratulate these individuals and appreciate their contribution. We also welcome other new staff members both at the head office and in the field. Our corporate morale is high as we meet the demands of a much higher activity level than in prior years, and we remain confident our people have the commitment to repeat and accelerate our performance in 2004.

In 2003, shareholders elected two new directors, Mr. Gary Freeman and Mr. Stewart McGregor. These gentlemen bring a wealth of experience to the boardroom and we welcome them and extend our appreciation for their commitment and involvement. Finally, Mr. Don Copeland, our Chairman, had indicated he would not be standing for re-election at our next Annual Meeting and subsequently resigned. We thank him for his support and contribution over the past few years.

Respectfully submitted on behalf of the board,

Signed,

"R.A. Gusella"

R.A. Gusella
President and Chief Executive Officer
March 26, 2004

Connacher is now on the cusp of

significant growth

review of operations

OVERVIEW

Connacher increased its position in western Canada during 2003. Over 90 percent of its assets, production, cash flow and planned activity is now located in Canada. Only two years ago the company's exposure was largely in Argentina. This redirection was coordinated by a management team with considerable experience. As activity has expanded, the operations team has been strengthened both at head office and in the field. Connacher is now on the cusp of significant growth in drilling activity, production, reserves and value enhancement.

The company expanded its domestic operations early in 2003 through acquisitions in the Battrum and Cabri areas of Saskatchewan. Later in the year, Connacher secured two large farm-ins covering over 100,000 gross acres, favourably situated within our southwest Saskatchewan focus region. The farm-ins meant that Connacher could tie up large spreads of prospective land while focusing its capital on drilling wells instead of funding up front land costs.

Connacher expects to continue its expansion in this manner, although our 2004 focus will be more on processing assets we now control rather than on acquiring new opportunities because our inventory of drillable opportunities is considerable.

Our capital expenditures in 2003 were $36 million, about four times greater than 2002. Almost all our investments were in Canada with the exception of a 50 percent interest in the drilling of one exploratory well in Argentina. Of our total expenditures, 45 percent or about $16 million was spent on drilling, completions equipping and workovers, $10.8 million was spent on the acquisition of producing properties, $3.4 million on land acquisitions and retention, $4.6 million on our Cabri natural gas production facilities and the balance of $1 million on seismic and administrative assets.

We financed these expenditures from total resources consisting of cash flow ($3.4 million), equity ($15 million) and debt ($17.3 million) while increasing cash balances.

As a result of our activity, we perpetuated our string of eleven successive quarters of production growth. On an annual basis our average daily production has grown from only 161 boe/d in 2001 to 568 boe/d in 2002 and then to 987 boe/d in 2003. Furthermore, we expect to accelerate production growth in 2004.

Our reserves have also grown, as we successfully applied our capital at Battrum, Cabri, Islay and in Argentina. Including acquisitions, Connacher replaced over 11 times its 2003 production with its capital program. Based on independent evaluations pursuant to NI 51-101, at year end 2003 Connacher owned 3.1 million proved boe, 5.6 million proved and probable boe and 7.1 million proved, probable and possible boe. The proved and probable reserves are forecast to generate $67.1 million of future cash flow over their economic life with an eight percent pre-tax present worth of $45.5 million. The independent evaluator estimates Connacher will have to invest an incremental $9.8 million over last year's estimate to realize forecast future production and cash flow. Connacher's 2003 proved and probable reserves are approximately 3.2 times year-end 2002 levels for established reserves, and at 0.17 boe per weighted average share is 89 percent above last year's level of 0.09 boe per share. Based on fourth quarter 2003 production, our proved and probable reserve life index was 12.4 years at December 31, 2003.

Connacher's field efficiency also improved in 2003. Both operating costs and general and administrative expenses per boe produced declined sharply as a percentage of revenue. As a result, and despite an almost doubling of unit royalties due to the purchase of some mature properties, the company's field netback improved 40 percent to average $14.25 per boe produced, 52 percent of revenue. In 2002, this measure was only $10.15 per boe or 49 percent of revenue with significantly lower royalties. We are relentless in our pursuit of both a higher-value commodity mix and further administrative and operating efficiencies.

Connacher's inventory of new acreage and drillable prospects expanded dramatically during 2003. At year-end we owned various interests in over 67,000 gross acres (61,000 net acres) in western Canada and 47,500 net acres in our Puesto Morales concession in Argentina. As we drill, further lands are being earned in our Tompkins and Divide farm-ins, and we also acquired over 50,000 acres of oil sands rights in early 2004. At year-end our Canadian land was appraised at $3.4 million compared to only $1 million last year.

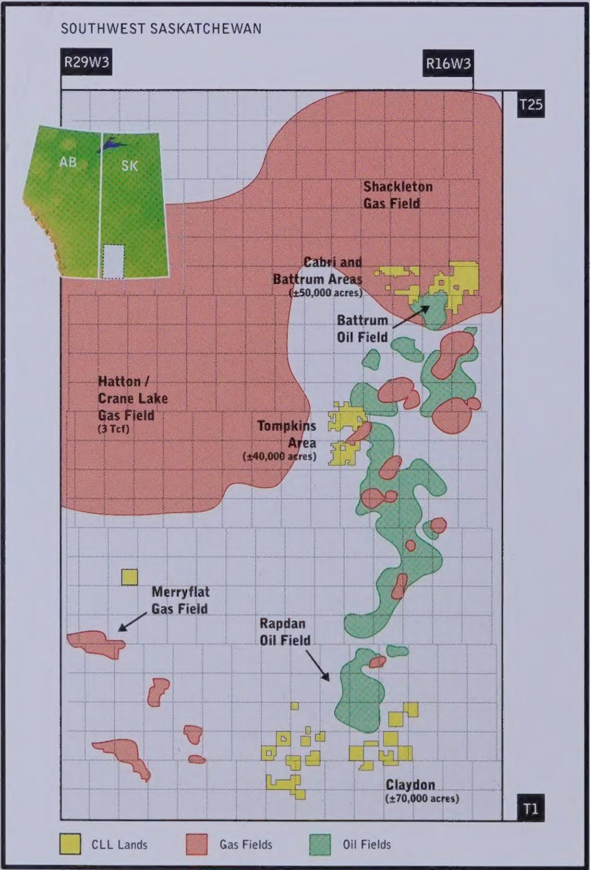
The operating outlook for 2004 is upbeat. Significant production and reserve growth is anticipated if we can remain on schedule and achieve the risked success we target. Our biggest challenge is to resolve Cabri startup issues and to secure requisite service company support on a timely basis to keep on track. In 2003 we encountered numerous delays in conducting "fracs" as originally scheduled for our November completion and tie-in program at Cabri. This delayed us considerably and resulted in new production coming on stream almost seven weeks behind schedule, putting startup right in the middle of extremely cold weather conditions. Similar delays have already been experienced in early 2004. Events such as these impact our overall production, revenue and cash flow forecasts. We will monitor development and revise our guidance as events unfold.

Our head office technical group and field operating staff were extremely busy last year and efforts have been undertaken to expand and strengthen our capability. The outstanding efforts of our personnel and their commitment to Connacher's goals and objectives are critical to our success and are appreciated.

canadian operations

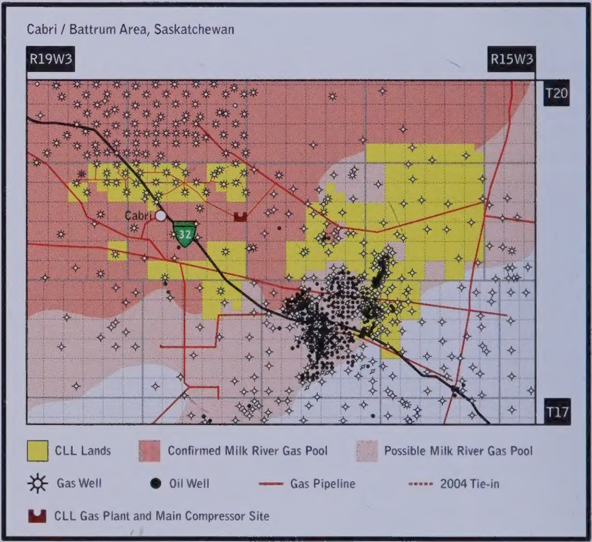
OUR APPROACH

Southwest Saskatchewan became a very important region for Connacher in 2003. Central to the company's domestic expansion was its acquisition of additional reserves and production at Battrum, Saskatchewan. Connacher subsequently completed geological studies in the area, which included recognition of shallow natural gas potential being pursued and realized by other operators north of its Battrum properties at Shackleton.



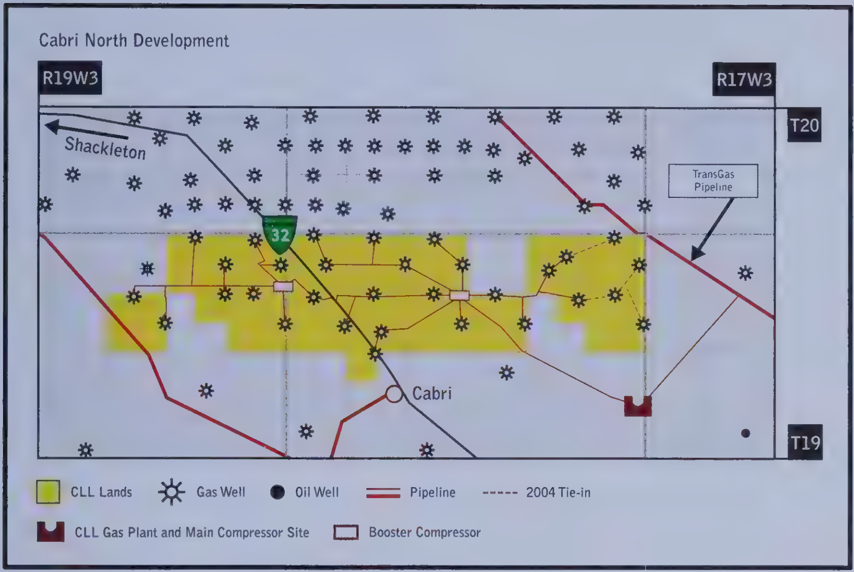
Connacher demonstrated its ambition and flexibility by adjusting its original 2003 plan, as indicated in last year's annual report, and entered into this Milk River natural gas play with commitment. We did so because we wanted more participation in higher value natural gas to mitigate the heavy oil exposure that dominated our original Canadian asset base at Lloydminster and Islay in Alberta. Since March 2003, Connacher secured almost 50,000 net acres of petroleum and natural gas (P&NG) rights in the area. Then, starting in July, we drilled 36 natural gas wells and acquired three others with a 100 percent working interest, tied in 26 of 31 wells on our Cabri North Block and commenced production into the TransGas system by December 21, 2003. This is what we mean by focus and commitment.

Our expansion at Battrum and Cabri underscores our approach to a new area. Firstly, our management had prior technical and operational knowledge of the area and its potential from industry experience. Secondly, the area had multi-zone potential with recognized producing reservoirs. Operatorship and large working interests were available, so we could control our pace of activity and realize the full effect of successful programs. There was ample available Crown land to facilitate expansion upon success. Finally, drilling costs and geological risks were known to be relatively low. The combination of these characteristics, plus the recognized natural gas potential which would lighten our production mix and improve our economics, caused us to move aggressively. We now own meaningful oil and natural gas reserves, production facilities tied into major natural gas and oil pipelines and have identified infill potential to sustain and grow production.



We also plan to initiate a high-potential tertiary recovery pilot program on our late-stage waterflood production of medium crude at Battrum, our original asset in the area. This is in keeping with our commitment to optimize the productive potential of all our properties, both new and more mature. If successful, the process could be applied field-wide with material impact on our oil reserves and production, while opening doors to new regions where the application of similar recovery techniques might be suitable. Our search for "hidden value" continues alongside our more conventional activity.

Having established a base in a region also opens the door to new opportunities. Our Tompkins and Claydon properties as discussed below provide excellent examples of how getting established in an area can also lead to deal flow and more attractive opportunities.



CABRI, SASKATCHEWAN (NATURAL GAS)

During 2003, close to 40 percent of Connacher's capital program was invested in identifying, delineating and developing shallow Milk River natural gas reserves and production in the Cabri area, situated at the southern edge of the Shackleton natural gas play.

Our program included land acquisition and an initial round of drilling to confirm the presence of reserves, followed by various initiatives to determine the lowest cost yet best methods to use in the drilling, logging and completion of development wells in order to optimize economic returns. The Cabri drilling program commenced in July 2003 and we quickly decided to focus on developing our Cabri North block. This was to minimize drainage as it directly offset existing production owned by another operator. A total of 31 wells were drilled on this portion of our Cabri acreage before year end.

In our development phase, we achieved considerable cost efficiencies, and were able to drill and case wells in as little as 24 to 28 hours at a cost under $75,000 per well. Subsequently these wells were perforated, subjected to a CO_2 frac and tested for various periods to ascertain deliverability. A decision was made to proceed with a natural gas gathering facility, installation of dehydration and compression and pipeline tie-ins in the fall while initially targeting a November 2003 startup.

Our startup was delayed until late December, mostly due to having to wait on available fracing units throughout the second half of the year. This was in part reflective of the high level of industry activity in developing shallow, tight gas-bearing sands, the impact of a CO_2 plant turnaround which curtailed supply, as well as the occasional shortage of suitable sand for fracing purposes.

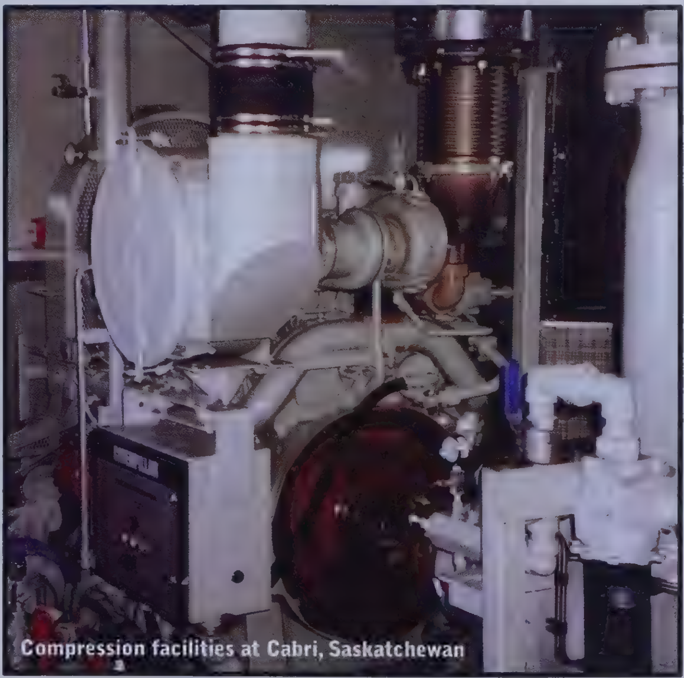
Regardless, we persisted and were able to commence Cabri gas production through our five mmcf/d facility on December 21, 2003, only five months after the commencement of our drilling program in the region. To recap, during this time we completed 26 of 31 wells, finalized engineering and design work, and also installed 28 miles of gathering lines, two booster compressors and one main compressor and associated dehydration facilities.

Unfortunately, shortly after startup we were subjected to mechanical failures at one of our booster stations as well as extremely cold weather conditions. This resulted in the freeze up of our entire system. Two more storms, cold conditions and startup problems persisted throughout January and February 2004. While intraday deliveries in the early stages of production at Cabri surpassed six mmcf/d, the combination of the adverse circumstances has resulted in erratic and unreliable production levels since startup, averaging 25 percent to 40 percent of capacity. Periodic shutdowns have made it more difficult to evaluate individual wells as we were unable to flow them on a sustained basis. This also made reactivating these low pressure wells more challenging each time a shutdown event occurred because, as expected, the natural gas was produced with water.

Nevertheless, we will persist and various remedial efforts are expected to bring more favourable production rates. These efforts include some equipment modification, increased pipeline pigging to eliminate surges of associated water produced with the gas, additional tie-ins, some recompletions, completions in new shallower zones, and advancing plans to drill up to 10 infill deliverability wells near higher productivity locations.

We are also conducting extensive testing of the various productive zones within the Milk River on wells on our remaining acreage. Once these results are evaluated, we will decide on further development programs. Delays experienced to date may dictate deferral of a portion of this activity until 2005 to avoid further weather-related complications.

As production stabilizes, we still see the prospect of continuing reserve and production growth in the area. With over 50,000 acres on the play, there is the potential for Connacher to develop considerable new production.


Compression facilities at Cabri, Saskatchewan

BATTRUM, SASKATCHEWAN (MEDIUM CRUDE OIL AND NATURAL GAS)

In early 2003, Connacher successfully completed two significant acquisitions of reserves, production, facilities and land in the Battrum area of southwest Saskatchewan. The total consideration for properties after closing adjustments was approximately $10 million. Reserves with related production were acquired at a low cost per barrel.

The Jurassic Roseray Sand reservoir, from which most of the Battrum medium gravity oil production is secured, has excellent characteristics. All the requisite facilities are in place to handle the crude produced and the waterflood in operation at the field. Production is connected to the market via a pipeline. Operatorship was secured and working interests generally range between 75 and 100 percent so the acquired interest was meaningful and future activity could be directed and controlled.

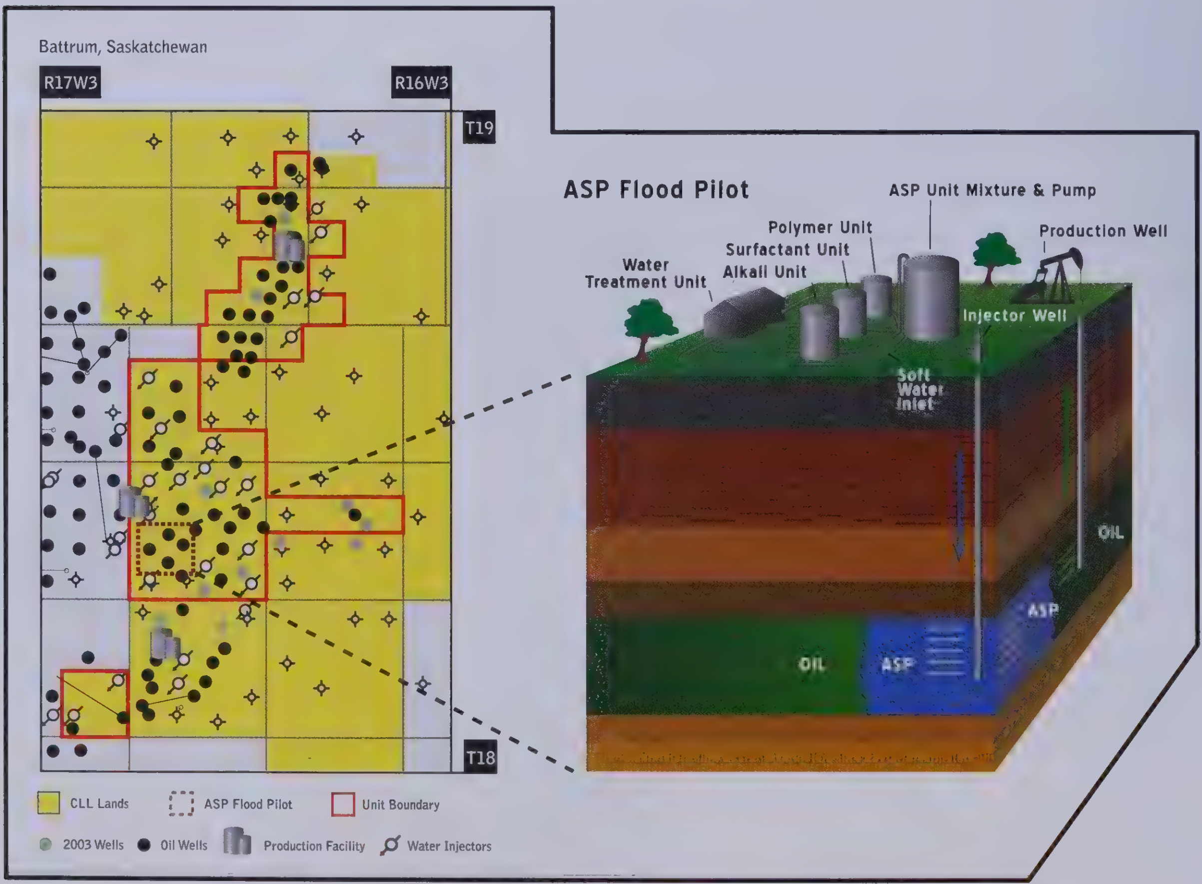
While the acquired production was mature, Connacher's management was very familiar with the property from prior corporate affiliations. They were largely responsible for optimizing the field's productivity in the 1980's when associated with a prior owner and operator. This level of managerial and hands-on field experience at Battrum is anticipated to benefit Connacher's shareholders.

During 2003, Connacher drilled and cased 11 gross (9.4 net) wells at Battrum trying to either capture unswept or attic oil or new outliers. Despite our familiarity with the property, results on completion were disappointing, and expected production growth failed to materialize at the levels originally contemplated. Several cased wells will be evaluated for uphole Milk River gas potential. Other wells can be used for injection purposes. Also, Connacher expanded its land base adjacent to Battrum production at Crown sales during the year. A 3-D seismic program has been conducted and 2-D seismic has also been acquired to assist in developing new drillable prospects for Roseray and Shaunavon oil.

On the enhanced recovery front, Connacher has now completed its laboratory work and in 2004 will activate a pilot program to evaluate the merits of an ASP tertiary recovery program on a small portion of the property. If successful, it would be applied field wide. This could materially enhance the level of recoverable reserves and production at Battrum on favorable economic terms.

In March 2003, Connacher hedged 250 bbl/d of Battrum oil production at a WTI price of $45.60 per barrel before quality differentials. This resulted in a realized wellhead price for hedged oil in excess of $30 per barrel, attractive by historic standards. Our unhedged volumes secured market price plus a small premium. The hedge was secured prior to the commencement of Iraq hostilities, after which crude prices declined sharply before recovering. The hedge provides Connacher with cash flow certainty in a volatile commodity market, enhances the loan value of the property to provide increased financial flexibility and reduces overall financial risk. Effective April 1, 2004 the 250 bbl/d hedge was renewed for one year at a WTI reference price of $44.08 before premium adjustment and quality differential.

Battrum is an important core area for Connacher because of its excellent reservoir, good current productivity, the exploration potential of new offsetting acreage, potential hidden value from the application of tertiary recovery methods, and possible exploitation of uphole behind pipe natural gas.



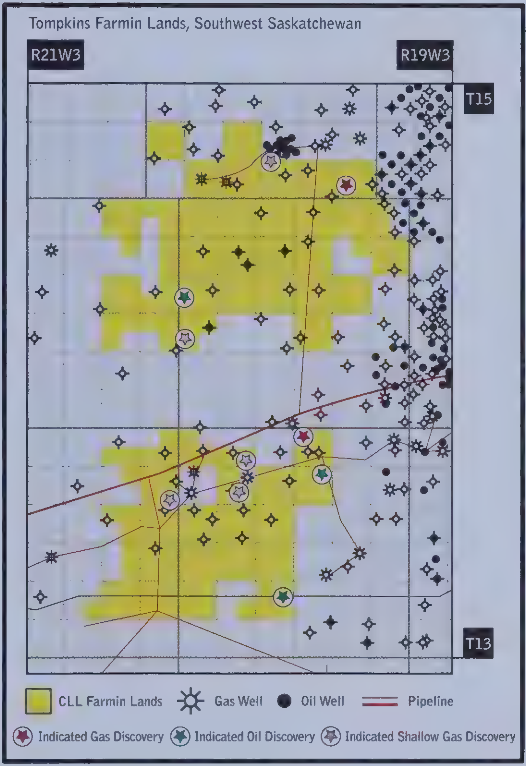
TOMPKINS AND CLAYDON, SASKATCHEWAN (CRUDE OIL AND NATURAL GAS)

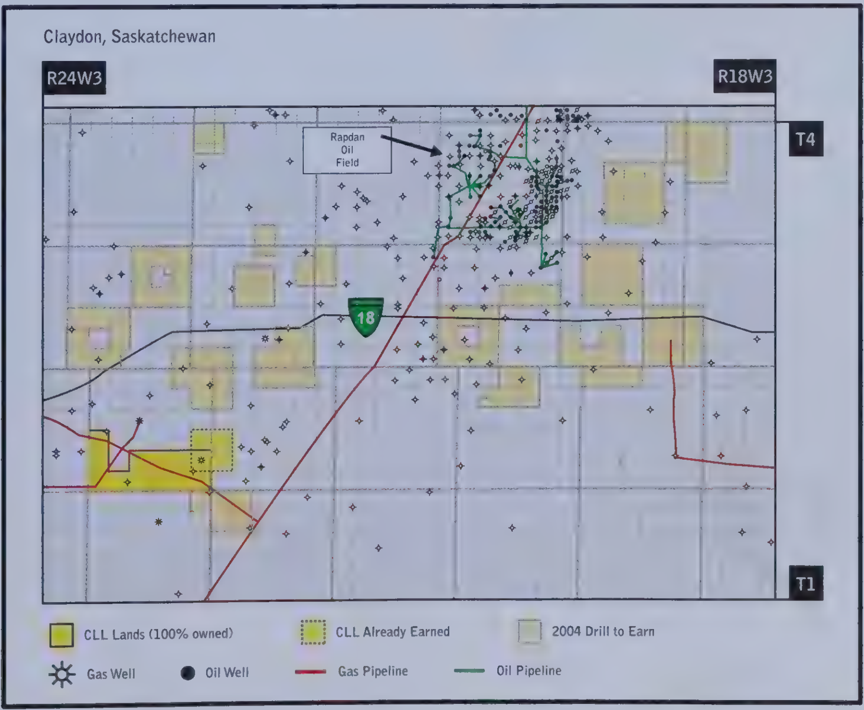
An important adjunct to the internal generation of drillable prospects for a small company such as Connacher is deal flow. Negotiated farm-in transactions can expose smaller concerns to significant growth opportunities. Often larger companies with extensive acreage holdings cannot process all of their land in a timely manner prior to expiry. Alternatively, such companies may redirect their priorities away from areas which might impact a smaller company considerably but would be of lesser consequence to a bigger concern. For Connacher, farming-in on these larger companies means we don't incur big upfront land costs so our capital is focused on drilling, which can earn large land spreads and develop bookable reserves and production.

Following up on favorable relationships established in our Cabri dealings, Connacher was able to secure two large farm-ins covering over 100,000 gross acres situated favorably within our southwest Saskatchewan focus region. These properties were similar to our lands at Cabri and Battrum. They were geologically prospective for shallow, high-value but low-risk Cretaceous natural gas and deeper Jurassic natural gas and oil. The areas, Tompkins and Claydon, were within 100 miles of the center of our operations at Battrum, with infrastructure and pipelines to accelerate market access opportunities. Good earning provisions were secured under these two large farm-ins, partly because of impending expiry deadlines.

We are happy to report that the first ten wells on the Tompkins farm-in acreage have been cased with several discoveries indicated from early testing. Our first well at Claydon was also cased with natural gas potential. Subsequently, additional offset Crown lands were acquired.

We met the minimum earning requirements of the Tompkins farm-in with our first four wells so our continued drilling earned additional acreage and tested new prospects. A residual four-well commitment remains at Claydon; up to ten option wells would only be drilled if early wells experience success. This commitment and rolling option approach is an attractive way to manage risk in new regions while leaving the door open to further drilling which can capitalize on early success.

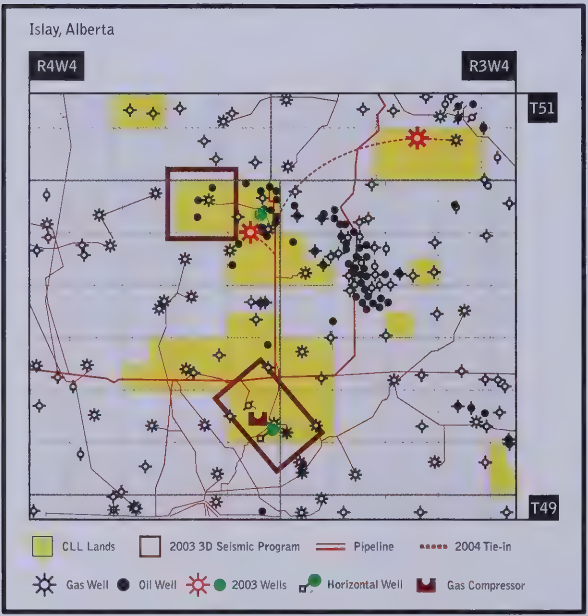




ISLAY, ALBERTA (HEAVY OIL AND NATURAL GAS)

Connacher holds largely 100 percent working interests in approximately 20 sections of developed and undeveloped acreage in the Islay heavy oil area of central eastern Alberta. Additional minor production is located at Lloydminster just east of our Islay property.

These properties were acquired in 2001 and 2002 and provided Connacher with a beachhead from which to expand its Canadian operating base. Less emphasis was placed on this area in 2003 due to our expansion in southwest Saskatchewan and due to the lower economic returns from a small heavy oil production base.



The primary target in this area is Sparky heavy oil within the Mannville Group. Secondary oil targets are the Lloydminster and GP zones, while natural gas, a secondary objective in this region, can be found in and produced from generally thin Rex, Sparky, McLaren and Colony zones, again all in the Mannville. With a natural gas gathering system and field compression in place, otherwise uneconomic natural gas can be commercially produced from the region.

In early 2003, we completed two new 3D seismic programs covering 4.6 square miles over significant, previously identified Lloydminster and GP channel prospects and also shot 12 new miles of 2D coverage to evaluate undrilled lands and to develop new oil and natural gas prospects. Connacher drilled four new wells in the area, including one horizontal location. Of the new wells, three were completed as oil wells and one as a natural gas well.

In early 2003, prior to the steep decline in crude oil prices following the commencement of military activity in Iraq, Connacher hedged 250 bbl/d of heavy oil from Islay and Lloydminster with pricing incentives for the commitment of its sales volumes to our crude purchaser. The negotiated hedge price for the 12-month period ended February 2004 was $30.83 per barrel for LLB Hardisty, or about 25 percent above the 2003 average price. The hedge enhanced the creditworthiness of these assets while assuring the company of a stable cash flow from this production, mitigating the risk of the impact of a possible collapse in crude oil prices. This is particularly consequential as we carry some debt on our balance sheet. The hedge was renewed for one year effective March 1, 2004 for 200 bbl/d at a WTI reference price of $ 42.67, before premium adjustment and quality differential.

Our Islay and Lloydminster acreage retains significant recognized reserve and production growth potential. It is a relativity low-cost area in which to conduct activity, with good access and strong service sector support. Although long-life reserves are achievable, there are operational and commodity valuation challenges and per well reserves are modest. Heavy 13° to 15° API oil is the primary objective, so quality differentials and seasonal price fluctuations can result in netback volatility.

While we will continue to harvest this asset, our medium term strategy is to aggressively exploit and develop our natural gas potential on this property while keeping costs under control.

STEELMAN, SASKATCHEWAN AND OTHER AREAS

Connacher drilled one 100 percent-owned horizontal oil well at Steelman in 2003. The well was located on property acquired at low cost in conjunction with our Battrum purchase. As light oil is produced, it provided the prospect of attractive economics upon success. The well was cased as an oil producer, but failed to yield the level of production we had hoped to establish. Subsequently, Connacher has completed a reservoir study which concluded pressure maintenance is likely required to achieve improved production levels. Further drilling also appears to be warranted.

During 2003, Connacher also drilled one well at Hazlet, Saskatchewan and one well at Bindloss, Alberta.


June 2003 operations in Southwest Saskatchewan

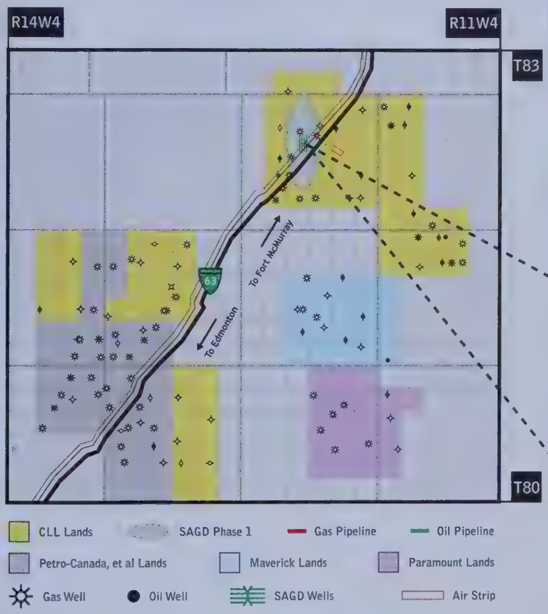
GREAT DIVIDE OIL SANDS PROJECT

Further enhancing Connacher's strong growth potential was its early 2004 acquisition of a 100 percent working interest in approximately 2 1/3 townships (over 54,000 acres) of oil sands leases in the Divide or Hangingstone region of northeast Alberta. Connacher's purchase is consistent with its long-term strategy of securing low cost exposure to big oil accumulations while capitalizing on its in-house expertise in the application of SAGD (steam-assisted gravity drainage) technology to shallow tar sands oil. The company was successful in acquiring six of the eight leases it posted, including its priority blocks, for slightly more than $1 million.

Connacher believes the leases could easily contain over one billion barrels of oil-in-place. They are geographically well-situated as they are readily accessible from the main Edmonton-to-Fort McMurray highway which intersects the property. The main pipelines from Fort McMurray which transport both tar sands oil and natural gas also intersect the acquired acreage. Following completion of initial geological studies, Connacher completed an 11-well corehole program to further delineate the reserve potential of one of several sand channels on its acreage. Based on logs, initial results are very encouraging. Upon application of appropriate capital, this accumulation and others on the block could eventually add material reserves and productivity to Connacher's resource base as recovery factors could average as high as 50 percent. An initial pad of eight to ten well pairs would be required to exploit this channel. With appropriate financing, it is feasible that a commercial project could be on stream by early 2006.

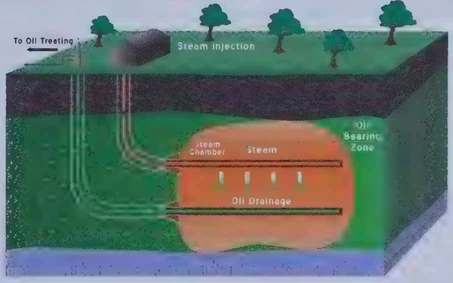
Connacher will be evaluating optimum financing alternatives during 2004 aimed at retaining, at minimum dilution, as much of the value of the asset as possible for its shareholders. This may entail creation of a privately or publicly funded sidecar company or joint venturing with a larger concern while retaining operatorship and control of the property. As this type of asset has the ideal characteristics of a royalty trust, we may also eventually examine this alternative ownership structure for our shareholders.

Great Divide - Oil Sands Leases (± 54,000 acres)

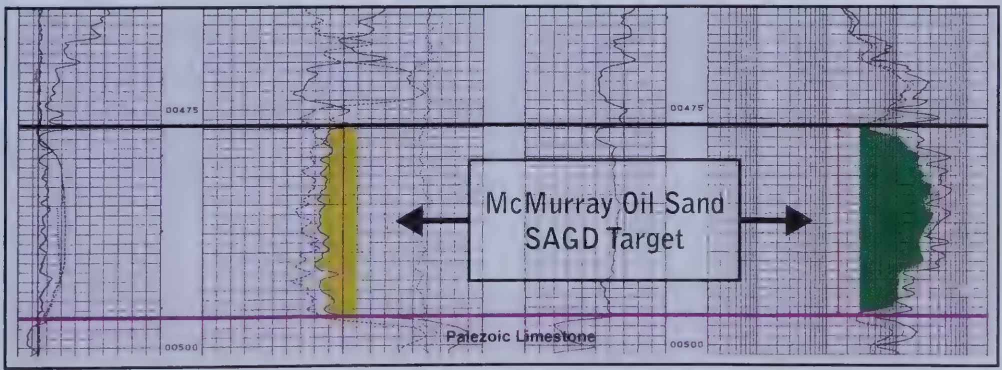


securing low cost exposure to big oil...

SAGD Schematic - Horizontal Well Pair

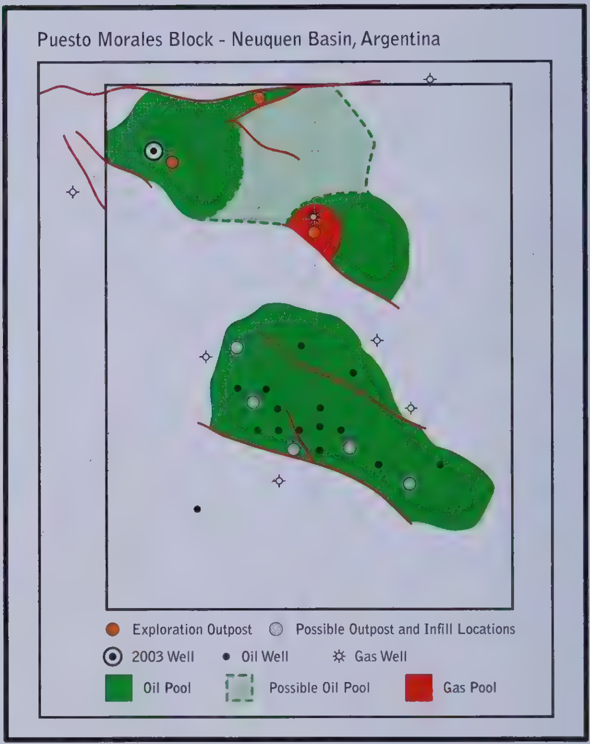


Great Divide Oil Sands Project - Type Log



argentinian operations

PUESTO MORALES / RINCONADA CONCESSION (LIGHT OIL AND NATURAL GAS)



Connacher owns a 50 percent non-operated working interest in the 95,000 acre Puesto Morales / Rinconada concession situated in the prolific Neuquen Basin of Argentina. The block is situated some 600 miles southwest of Buenos Aires in close proximity to several large established oilfields, including some of giant status with over one billion barrels of recoverable oil. Hydrocarbons are largely produced from various zones within the Lower Cretaceous Loma Montosa Formation. Gross production from the concession in 2003 averaged 96 bbl/d of oil and 1.1 mmcf/d of natural gas, with natural gas sales consisting of associated natural gas volumes from Puesto Morales Sur and non-associated natural gas from the Puesto Morales Norte field situated near the northern edge of the Puesto Morales block, which comprises a significant part of the concession.

The oil produced is sweet 35° to 37° API crude and it was sold at an average price of $37.74 during 2003. Unfortunately, natural gas sales only received a price of $0.23/mcf last year. This was due to a price freeze at one peso per mcf imposed by the Government of Argentina in late 2001, higher processing costs and the deterioration of the peso/dollar relationship.

In early 2003, we agreed with the operator to conduct a limited seismic program over the structure associated with Puesto Morales Norte. We had secured seismic from offsetting property owners which indicated the likelihood of a fairly large feature on our block, which might also extend to the west and northwest into adjoining acreage.

Based on the seismic interpretation, Connacher and the operator elected to drill the PMx1001 exploratory well on the La Ramona prospect. The cost of the well was financed from Argentinian cash balances and cash flow.

The PMx1001 well was spudded on September 20, 2003 and reached a total depth of 1,672 metres on October 4, 2003. Based on drilling results and subsequent log analysis, the well was cased. Testing of five separate intervals within an oil column exceeding 260 metres was then initiated. Approximately 30 metres of oil bearing zones were perforated within four separate intervals that comprise most of the oil column. A fifth zone at the base of the well was perforated, swabbed and recovered oil and water and was then isolated behind a bridge plug.

The four remaining uphole pay zones were stimulated with acid and then swabbed. Based on the oil recoveries, the well was placed on stream, initially recovering load fluid. Within two days the well was producing at an indicated rate of 54 barrels of oil per day with no water. Subsequently well productivity declined and it now appears the stimulation program was ineffective.

The oil which was produced has a density of approximately 840 grams per litre (approximately 37° API sweet light crude), similar to that currently being produced at the Puesto Morales Sur field to the south of the discovery well. This oil is sold for 90 percent of the prevailing WTI price, so netbacks are favourable. Prevailing royalty rates are 13 percent.

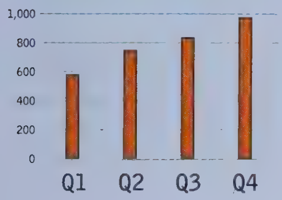
The La Ramona structure has been seismically defined and covers a considerable area. Additionally, there are other associated structures which are viewed as highly prospective for hydrocarbon accumulations in other zones. Accordingly, while it is premature to estimate the recoverable reserves of the project and well productivity issues remain to be resolved, Connacher's management is of the opinion, based on the facts currently available, that the concession may yet yield results which could have a substantial impact on Connacher's future production levels and reserve base.

Connacher representatives have met with the operator to establish its program for 2004. This will likely include recompletion of the discovery well as it appears the initial frac was compromised. Also, another exploratory step-out well is being considered along with development opportunities. For planning purposes, five new drilling locations have been identified and could be drilled on the block if early success is achieved and cash flow growth from the area is assured. Capital expenditures in Argentina are expected to remain under ten percent of Connacher's outlays and efforts continue to ensure this project can be self-sufficient.

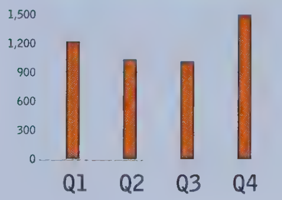
production, reserves, land and estimated net asset value

PRODUCTION

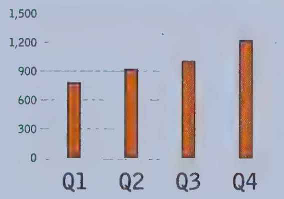
2003 Daily Crude Oil Production and Sales (bbl/d)



2003 Daily Natural Gas Production and Sales (mcf/d)



2003 Equivalent Barrels Production and Sales (boe/d)



Connacher's 2003 production rose 74 percent over last year; oil production rose 132 percent, while natural gas sales declined 13 percent.

Of total oil production, 94 percent was in Canada and six percent was in Argentina. Natural gas sales were more balanced, with 53 percent in Canada and 47 percent in Argentina.

Of total boe sales, seven percent was light oil in Canada and Argentina, 42 percent was medium gravity crude oil and 20 percent was natural gas. Heavy oil accounted for 31 percent of daily production in 2003.

Connacher's objective continues to be a lightening of its product mix such that natural gas is around 50 percent of production with light and medium crude at 35 to 40 percent and heavy oil the remainder. This is consistent with our 2004 plan.

Connacher's oil production grew steadily throughout 2003, reaching its peak in the fourth quarter. This reflects the impact of the company's capital program. Significant production purchases at Battrum earlier in the year and our second half capital program influenced production results. December oil production surpassed 1,000 bbl/d although the level was below our plan.

Much of our spending was on natural gas drilling and facilities which made minimal contribution to 2003 results but are expected to impact 2004, as Cabri production and sales were initiated on December 21, 2003.

2003 Average Daily Production

	Q1	Q2	Q3	Q4	Full Year
Oil (bbl/d)					
Islay, Alberta	284	291	310	338	306
Battrum, Saskatchewan	245	406	461	546	415
Steelman, Saskatchewan	7	8	22	41	20
Argentina	46	47	46	53	48
TOTAL	**582**	**752**	**839**	**978**	**789**
Natural Gas (mcf/d)					
Islay, Alberta	655	432	480	673	560
Steelman, Saskatchewan	-	17	16	17	13
Cabri, Saskatchewan	-	-	-	240	60
Argentina	561	584	517	566	557
TOTAL	**1,216**	**1,033**	**1,013**	**1,496**	**1,190**
Equivalent barrels (boe/d)					
Islay, Alberta	393	363	390	450	399
Battrum, Saskatchewan	245	406	461	546	415
Steelman, Saskatchewan	7	11	25	44	22
Cabri, Saskatchewan	-	-	-	40	10
Argentina	140	144	132	148	141
TOTAL	**785**	**924**	**1,008**	**1,228**	**987**

RESERVES

At year end, Connacher's oil and natural gas reserves were primarily located in Southwest Saskatchewan and at Islay, Alberta in Canada and at Puesto Morales in the Neuquen Basin in Argentina. Outtrim Szabo Associates Ltd., Petroleum Consultants of Calgary, Alberta, (Outtrim Szabo) evaluated the company's reserves as at December 31, 2003 in a report dated March 26, 2004. Their report included an evaluation of proved, probable and possible reserves. The following table summarizes the Outtrim Szabo report which was prepared using assumptions and methodology guidelines outlined in the "Canadian Oil and Gas Evaluation Handbook" and in accordance with NI 51-101.

Under NI 51-101, proved reserve assignments are based on a 90 percent certainty that total quantities recovered will equal or exceed proved reserve estimates. Proved plus probable reserves are the most likely case and are based on a 50 percent certainty that they will equal or exceed estimates. The new standard provides for a more conservative evaluation of proven and probable reserves, particularly on new wells where production history has not yet been established. The change to proved and probable reserve definitions implemented by NI 51-101 for the year ended December 31, 2003, may make reserve quantity and reserve valuation comparisons to prior years difficult. Management believes the most meaningful comparison of the current year's proved plus probable reserves would be to "established reserves" of prior years (being proved plus 50 percent probable).

Connacher's proved and probable reserves total 4.1 million barrels of crude oil and liquids and 8.6 bcf of natural gas. Outtrim Szabo estimates these reserves will generate $67 million of future net revenue before income tax but after royalties, capital expenditures and abandonment costs net of salvage value with an eight percent present worth of $45.5 million.

Outtrim Szabo also estimates that Connacher's share of the total undiscounted capital required and abandonment costs provided for in their estimate of future cash flow is as follows:

Reserve Category	Capital Costs ($000)	Abandonment Costs ($000)
Total Proved	6,440	3,408
Probable	4,553	713
Total Proved and Probable	10,993	4,121
Possible	8,296	202
Total Proved, Probable and Possible	19,289	4,323

These expenditures are forecast to occur on a year-by-year basis, as required, over the life of the company's properties and are deducted prior to the calculation of undiscounted and discounted future cash flow.

The report estimates 90 percent of the company's future net revenue from proven and probable reserves is located in Canada. The balance is located in Argentina. Accordingly, Connacher continued its transformation during 2003 from having its major asset in Argentina to having a more diversified reserve and acreage platform over a higher number of wells in a politically and economically stable country. Furthermore, approximately 25 percent of Connacher's proved and probable reserves are now natural gas. This trend will continue in 2004.

Remaining Reserves and Future Cash Flow
Escalating Prices at December 31, 2003
Company Share – Escalated Dollar Economics

	Remaining Reserves						Future Net Revenue (4, 5, 6)		
	Crude Oil		Natural Gas		NGLs		Undis-	Discounted	
Reserve Category	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)	counted	at 8%	at 10%
	stb	stb	mmcf	mmcf	bbl	bbl	$000	$000	$000
Proved Developed									
Producing	1,647,968	1,398,980	2,785	2,611	2,585	1,826	26,219	21,517	20,609
Non-Producing	182,695	152,626	1,439	1,275	-	-	5,784	4,585	4,356
Total Proved Developed	1,830,663	1,551,606	4,224	3,886	2,585	1,826	32,003	26,102	24,965
Proved Undeveloped	341,044	312,134	1,237	1,155	-	-	4,156	2,282	1,994
TOTAL PROVED	2,171,707	1,863,740	5,461	5,041	2,585	1,826	36,159	28,387	26,959
Probable	1,972,599	1,678,051	3,092	2,876	1,252	893	30,955	17,151	15,225
TOTAL Proved & Probable	4,144,306	3,541,791	8,553	7,917	3,837	2,719	67,114	45,538	42,184
Possible(3)	1,316,993	1,204,386	1,004	988	119	104	18,298	9,492	8,134
TOTAL Proved & Probable & Possible	5,461,302	4,746,177	9,557	8,905	3,956	2,823	85,412	55,030	50,318

(1) Before royalty deduction, net to company interest.
(2) After royalty deduction, net to company interest.
(3) Possible reserves are those reserves less certain to be recovered than probable reserves. There is at least a 10 percent probability that the quantities actually recovered will exceed the sum of the estimate of proved plus probable plus possible reserves.
(4) The values do not necessarily represent the fair market value.
(5) Excluding ARTC, which is evaluated separately and is forecast to have an undiscounted value of $1.1 million, an eight percent discounted value of $849,000 and a 10 percent discounted value of $804,000.
(6) Before income taxes and indirect costs and after capital costs and future abandonment costs net of salvage value.
(7) May not add due to rounding.

Reserve Reconciliation (1,2,3)
2003 Year End

	Oil and NGLs (mbbls)				Natural Gas (mmcf)				Equivalent (mboe)			
	Prov.	Prob.	Poss.	Total	Prov.	Prob.	Poss.	Total	Prov.	Prob.	Poss.	Total
At December 31, 2002	1,023	177	n/a	1,200	2,940	429	n/a	3,369	1,513	248	-	1,761
Extensions	302	151	136	589	3,718	1,871	217	5,806	921	464	172	1,557
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Revisions of Prior Estimates	(365)	254	173	61	(1,250)	345	672	(233)	(573)	312	285	24
Acquisitions	1,502	1,391	1,009	3,902	474	446	120	1,040	1,581	1,465	1,028	4,074
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Production	(288)	-	-	(288)	(420)	-	(5)	(425)	(358)	-	-	(358)
At December 31, 2003	2,174	1,974	1,317	5,465	5,462	3,091	1,004	9,557	3,085	2,489	1,484	7,058

(1) Certain adjustments were made to opening balances for probable reserves in order to compare 2003 reserve estimates calculated pursuant to NI 51-101 to 2002 "established" reserves.
(2) May not add due to rounding.
(3) Calculated based on escalated dollar economics as at December 31, 2003.

During 2003, Connacher replaced over 1,150 percent of its expanded annual production of 360,000 barrels, adding 4.2 million proved and probable boe. This was accomplished with a total capital program attributable to oil and gas activities of $35.4 million, of which $10.8 million represents the company's net outlays to acquire producing properties at Battrum and Steelman. Accordingly, a total of $25.8 million was invested in land acquisition, seismic, drilling and workovers and production facilities during the year.

Pursuant to NI 51-101, finding and development (F&D) costs and finding, development and acquisition (FD&A) costs for a given year are calculated by dividing actual expenditures by the reserve additions achieved by the company in that related activity. These costs are also calculated before and after adding incremental future capital required to realize forecast net revenue, as estimated by the independent evaluator. For Connacher, this amounts to $9.8 million for all properties owned at year end 2003. Connacher's management is of the opinion that FD&A costs, calculated either before or after such projected future costs, are more representative of its business, as property acquisitions are expected to continue to be an integral part of Connacher's growth strategy, alongside its exploratory, development and facilities construction programs.

Connacher's F&D and FD&A costs for proved and probable reserve additions in 2003 are as follows:

2003 F&D and FD&A Costs

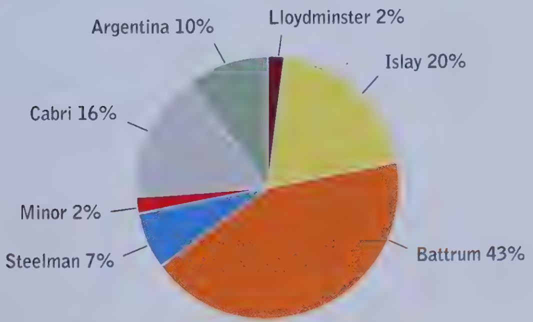
	Total ($MM)		Per Boe ($)	
	Incurred	With Future Capital	Incurred	With Future Capital
F&D Costs	24.6	34.4	20.50	28.67
Acquisition Costs	10.8	10.8	3.60	3.60
FD&A Costs	35.4	45.2	8.47	10.82

Related Reserve Additions (1)
Acquisitions - 3.0 million boe
Extensions and revisions before production - 1.2 million boe
Total Additions - 4.2 million boe

(1) May not reflect full impact of capital program depending upon timing of activity and startup of production.

Based on fourth quarter 2003 production, Connacher's life index for proved reserves was 6.9 years and 12.4 years for proved and probable reserves.

Percentage Distribution of Proved and Probable Reserves by Area (5.6 mmboe)



LAND

Connacher holds various interests in approximately 26,924 hectares (67,310 acres) of undeveloped petroleum and natural gas rights in Alberta and Saskatchewan. No oil and natural gas reserves have been assigned to this property. The company's average interest in its undeveloped acreage is approximately 91 percent.

In a report dated March 1, 2004 prepared by Seaton-Jordan & Associates Ltd., (Seaton-Jordan), independent mineral management consultants of Calgary, Alberta, a fair value of $3,380,490 or approximately $126 per gross hectare was assigned to Connacher's non-reserve oil and gas properties. This equates to approximately $50 per acre. In determining the market value, Seaton-Jordan based their evaluation on the following factors:

1. The acquisition cost, provided that there have been no material changes in the unproved property, the surrounding properties, or the general oil and gas climate since the acquisition;
2. Recent sales by others of interests in the same unproved property;
3. Terms and conditions, expressed in monetary terms, of recent farm-in agreements;
4. Terms and conditions, expressed in monetary terms, and of recent work commitments related to the unproved property; and
5. Recent sales of similar properties in the same general area.

This complies with the Securities Commission Standards of Disclosure as described in paragraph (a), subsection (2), Section 5.10 of NI 51-101.

Connacher did not commission an evaluation of its Argentinian undeveloped acreage. The company owns a 50 percent undivided working interest in the 95,000 acre Puesto Morales / Rinconada Concession, which is largely undeveloped.

ESTIMATED NET ASSET VALUE

Connacher's estimated net asset value, as at December 31, 2003 is as follows:

Estimated Net Asset Value (Pre-tax)
as at December 31, 2003

	Total ($000)	Per Share (1) ($)
Reserves at 10% DCF	50,318	1.20
ARTC @ 10% DCF	804	0.02
Land	3,380	0.07
Total Assets	54,502	1.29
Less:		
Net debt	21,094	0.46
Net Asset Value	33,408	0.73

(1) Based on 45.9 million shares.

Fully-diluted with the exercise of outstanding warrants and options, there would be 53.7 million shares outstanding. The company would receive $4 million if all such options and warrants were exercised and the fully-diluted value would calculate at $0.70 per share.

No provision is included for the company's oilfield inventory, seismic or undeveloped Argentinian acreage in the above calculations. Importantly, 145 percent of estimated net asset value is in the form of reserves and Connacher had 0.17 boe of reserves per weighted average share outstanding, double last year.

management's discussion & analysis

The following is dated as of March 26, 2004 and should be read in conjunction with the Consolidated Financial Statements of Connacher Oil and Gas Limited for the years ended December 31, 2003 and 2002 as contained in the annual report. This discussion and analysis provides management's view of the financial condition of the company and the results of its operations for the reporting periods. Information contained in this report contains forward-looking information based on current expectations, estimates and projections of future production, capital expenditures and available sources of financing. It should be noted forward-looking information involves a number of risks and uncertainties and actual results may vary materially from those anticipated by the company. These risks and uncertainties include, but are not limited to, changes in market conditions, law or governing policy, operating conditions and costs, operating performance, demand for oil and gas, price and exchange rate fluctuation, currency controls, commercial negotiations and technical and economic factors. Per barrel of oil equivalent (boe) amounts have been calculated using a conversion rate of six million cubic feet of natural gas to one barrel of oil (6:1). The conversion is based on an energy equivalency conversion method primarily applicable to the burner tip and does not necessarily represent a value equivalency at the wellhead.

CORPORATE GROWTH OVERVIEW

Corporate Growth

	2003	2002	2001
FINANCIAL			
($)			
Total assets	**49,669,077**	10,254,881	1,706,359
Shareholders' equity	**24,485,541**	5,279,336	1,212,774
Bank debt and note payable	**12,160,000**	2,557,806	175,000
Total revenue	**9,982,291**	4,325,817	1,128,797
Cash flow from operations (1)	**3,352,778**	1,046,509	(151,738)
Net earnings	**4,190,316**	500,720	(1,214,215)
OPERATING			
Daily production / sales volumes			
Oil (bbl/d)	**789**	340	57
Natural gas (mcf/d)	**1,190**	1,365	624
boe/d (@ 6:1)	**987**	568	161
Proved and probable reserves (2)			
Oil & liquids (mbbls)	**4,148**	1,200	143
Natural gas (mmcf)	**8,553**	3,368	2,109
Equivalent (mboe)	**5,574**	1,762	495

(1) Cash flow from operations is not a measure that has any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by others.

(2) The reserve estimates for 2003 were prepared in accordance with National Instrument 51-101 (NI 51-101). Under NI 51-101, proved reserve assignments are based on a 90 percent certainty that total quantities recovered will equal or exceed proved reserve estimates. Proved plus probable reserves are the most likely case and are based on a 50 percent certainty that they will equal or exceed estimates. The new standard provides for a more conservative evaluation of proved and probable reserves, particularly on new wells where production history has not yet been established. The change to proved and probable reserve definitions implemented by NI 51-101 for the year ended December 31, 2003, may make reserve quantity and reserve valuation comparisons to prior years difficult. Management believes the most meaningful comparison of the current year's proved plus probable reserves would be to "established reserves" of prior years (being proved plus 50 percent probable). Prior year's "proved plus probable" reserves, above, are reflected on that basis.

(3) No dividends were declared by the company in the last three years.

Over the past three years Connacher's management has redirected the company's affairs to Canada following a recapitalization and reconstitution of the management and board of directors in July 2001. Since that time the company has selectively acquired oil and gas properties and developed prospects to successfully build shareholder value. Growth has been rapid but calculated. In its early stage of development, the company focused on heavier oil properties because they could be acquired on favorable terms and because of management's expertise and success in developing these types of assets. In 2003 the company balanced its assets with lighter oil and more natural gas, primarily through internal development and to some extent by way of acquisition as suitably priced opportunities were identified. The table above portrays the growth achieved over the past three years.

In January 2002 the company purchased producing oil and natural gas properties in the Lloydminster/Islay region of central eastern Alberta for $4 million and completed a well workover program and drilled 12 wells in that region, completing eight oil wells and two natural gas wells.

In January and February 2003 the company purchased producing oil and natural gas properties in the Battrum region of southwest Saskatchewan for $10 million. Subsequently, the company expanded into the Milk River gas play at Cabri, Saskatchewan and also drilled 59 gross wells (57 net wells), mostly in the second half of the year.

FINANCIAL AND OPERATING REVIEW

REVENUE, PRODUCTION AND PRICING

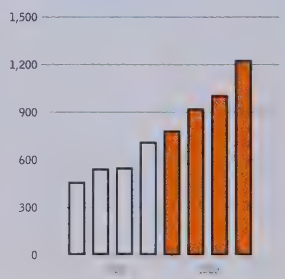
Total revenue for the year more than doubled to $10 million compared to $4.3 million in 2002 and $1.1 million in 2001. This reflects a 74 percent increase in sales volumes and a 34 percent increase in average product pricing in 2003. Canadian revenues were $9.2 million, up 151 percent from $3.7 million in 2002, while Argentine revenues were up slightly to $703,000 from $643,000 last year.

Revenue increases in 2003 and 2002 reflect significant production growth, primarily in Canada, where the company has focused most of its capital spending. This included major property acquisitions in early 2002 and early 2003 followed up with aggressive drilling and workover programs. Although these programs focused on oil and natural gas, only increases in oil production volumes are evident thus far. New natural gas production commenced in late December 2003 after construction of a gathering system and natural gas plant.

The most significant increase occurred in oil production, while Canadian natural gas sales declined in 2003, reflecting limited investment in existing properties as new reserves were being developed at Cabri where related

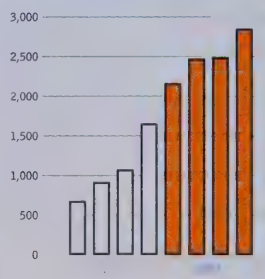
Quarterly

Production (boe/d)



Quarterly

Total Revenue ($000)



production did not commence until December 21, 2003. Argentinian production remained stable at around 150 boe/d in the past three years. On an equivalent basis, Connacher's 2003 production of 987 boe/d was 74 percent higher than in 2002, and increased six-fold over 2001.

As evidenced by the results, management focused on expanding its Canadian asset base, thereby increasing the impact of and contribution from domestic operations to solidify a lower-risk cash flow stream. This can then be redeployed in growth expenditures. With Canadian production growing and the contribution from Argentina relatively flat, by the fourth quarter of 2003 about 88 percent of Connacher's sale volumes were being produced in Canada, compared to only 17 percent in 2001.

Connacher will continue its pursuit of a rapid growth profile to expand its reserve base and increase production levels in 2004.

Production and Pricing

	2003	2002	2001
Daily production / sales volumes			
Oil – bbl/d			
Canada	741	294	17
Argentina	48	46	40
Total	**789**	**340**	**57**
Natural Gas –mcf/d			
Canada	633	811	60
Argentina	557	554	564
Total	**1,190**	**1,365**	**624**
boe – boe/d			
Canada	847	429	27
Argentina	140	139	134
Total	**987**	**568**	**161**
Product pricing			
Oil – per bbl			
Canada	$29.54	$24.22	$17.66
Argentina	$37.74	$32.22	$36.82
Average	$30.03	$25.30	$31.11
Natural gas – per mcf			
Canada	$5.34	$3.49	$7.98
Argentina	$0.23	$0.49	$1.47
Average	$2.95	$2.28	$2.09
boe – per boe			
Canada	$29.85	$23.19	$28.84
Argentina	$13.72	$12.72	$17.16
Average	$27.56	$20.64	$19.12

Prices in 2003 were firm. In Canada, crude oil prices were stronger, offset by the impact of the rising Canadian dollar in relation to the US dollar. The value of the Canadian dollar, relative to the US dollar, increased from $0.63 at December 31, 2002 to $0.77 at December 31, 2003. Despite this strength, which had the effect of reducing the Canadian dollar selling price of crude oil, overall corporate pricing for oil rose 19 percent over 2002, reflecting a successful hedging program and a lighter product mix.

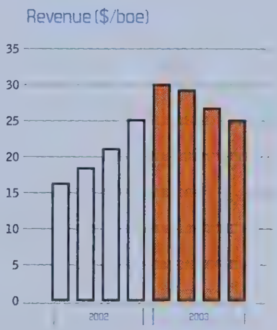
Canadian natural gas prices were also higher in 2003 but still below record levels reached in 2001 when they averaged close to $8.00 per mcf. Argentinian natural gas prices continued to be weak reflecting the relative strength of the Canadian dollar and the continued price freeze at one peso per mcf in Argentina.

Connacher's 2003 realized price per boe rose 34 percent to $27.56 from $20.64 per boe in 2002. The price was firm early in the year and then declined in the second half after hostilities abated in Iraq. Overall levels, though, remained above 2002, despite the strong Canadian dollar. To mitigate the vagaries of volatile price swings in the market for crude oil, which are beyond the control of the company, management employs a modest hedging strategy to fix the selling prices of a portion of its domestic oil sales in Canadian dollars. Being a small producer with medium gravity and heavy oil representing a meaningful percentage of total production, from time to time the company could be vulnerable to reduced pricing and variations in quality differential adjustments. Furthermore, as the company finances its growth with a bank debt component, it could be faced with the possible redirection of cash flow to debt reduction instead of growth expenditures during periods of low prices which fall below the price deck employed by its lender.

Accordingly, in early 2003 the company hedged 250 bbl/d of its Islay heavy crude oil production until February 28, 2004 at $30.83 per barrel for LLB Hardisty. A further 250 bbl/d of its Battrum crude was contracted until March 31, 2004 at a fixed price for WTI of $45.60 per barrel before deduction of the related crude oil price differential.

The company has renewed its Islay heavy crude oil hedge for 200 bbl/d for one year from March 1, 2004 until February 28, 2005 at a WTI base price of Cdn. $42.67 before quality differential adjustments. Certain other benefits accrue to Connacher in conjunction with the hedge as provided by the purchaser of the crude oil produced in this region. Effective April 1, 2004 the 250 bbl/d Battrum crude oil hedge was renewed for one year at a WTI reference price of $44.08 before premium adjustment and quality differential.

The company's reported revenues include gains and/or losses realized on the hedges; they are not separately reported in the consolidated financial statements. Since entering into the February 2003 hedges, world oil prices decreased. As a result, crude oil revenues realized in 2003 were higher than would have been reported had the company not entered into the 2003 hedges by approximately $203,000.



ROYALTIES

Royalties represent charges against production or revenue by governments and landowners. Royalties in 2003 were $1.8 million ($4.98 per boe, or 18 percent of oil and gas revenue) compared to $598,000 ($2.88 per boe, or 14 percent of oil and gas revenue) in 2002. The table below provides further detail by country for each year.

	Royalties			
	2003		2002	
	Total	Per boe	Total	Per boe
Canada	$ 1,722,900	$ 5.58	$ 528,213	$ 3.37
percentage of total oil and gas revenue	18.7%		14.5%	
Argentina	$71,540	$ 1.39	$ 69,421	$ 1.37
percentage of total oil and gas revenue	10.1%		10.8%	
Total	**$ 1,794,441**	**$ 4.98**	**$ 597,634**	**$ 2.88**
percentage of total oil and gas revenue	**18.0%**		**14.0%**	

Canadian royalties were higher in 2003 because the company acquired more mature properties at Battrum, Saskatchewan and increased its sales volumes at a higher royalty rate. Canadian royalties of $1.7 million are net of Alberta Royalty Tax Credits of $57,500.

OPERATING EXPENSES AND OPERATING NETBACKS

Company Operating Netbacks - combined Canada and Argentina (1)

	2003		2002		% Change 2003 - 2002	
	Total	Per boe	Total	Per boe	Total	Per boe
Average daily production (boe)	**987**		**568**		**74%**	
Oil and natural gas revenue	**$ 9,930,717**	**$ 27.56**	$ 4,276,480	$ 20.64	132%	34%
Other income	51,574	0.14	49,337	0.24	5%	(42%)
Total revenue	9,982,291	27.70	4,325,817	20.88	131%	33%
Royalties	(1,794,441)	(4.98)	(597,634)	(2.88)	200%	73%
Net revenue	8,187,850	22.72	3,728,183	18.00	120%	26%
Operating costs	(3,051,791)	(8.47)	(1,625,346)	(7.85)	88%	8%
Operating Netback	**$ 5,136,059**	**$ 14.25**	**$ 2,102,837**	**$ 10.15**	**144%**	**40%**

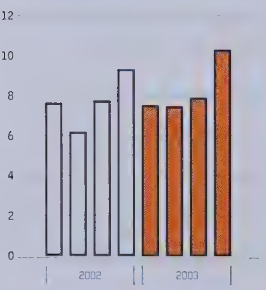
(1) Calculated by dividing related revenue and costs by total boe produced, resulting in an overall combined company netback.

Operating expenses increased by 88 percent year over year to $3.1 million, primarily reflecting higher production levels. Unit costs rose to $8.47 per boe compared to $7.85 per boe in 2002. Operating costs were particularly high in the fourth quarter of 2003 due to expensing of compression costs upon commencement of production at Cabri and late year workovers without immediate production response. Canadian costs at $9.03 per boe were higher than target for the reasons cited above.

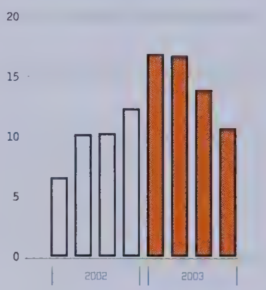
Efforts will continue to reduce these costs. As production is increased, unit costs will diminish when fixed costs are spread over the increased volumes. Argentinian unit operating costs were up from $4.03 in 2002 to $5.08 per boe as peso expenses increased following the 2002 devaluation of the Argentine peso. When converted to higher valued Canadian dollars for reporting purposes, costs are still low.

In Canada the overall operating netback was $15.25 per boe (2002 - $11.06) while in Argentina it was $7.24 per boe (2002 - $7.60). Argentina's decline reflected a higher cost structure with a devalued peso and weak natural gas prices. Canadian netbacks were particularly strong in the first half of 2003, peaking at over $20.00 per barrel in June, but weakened thereafter as prices fell and costs rose into the fourth quarter.

Operating Expenses ($/boe)



Company Netback ($/boe)



GENERAL AND ADMINISTRATIVE EXPENSES

Total general and administrative (G&A) expenses increased by 18 percent in 2003, reflecting additional staff as the company expanded its scale and scope of operations with a capital budget five times that of last year. Increases occurred for public company costs, financing fees and transaction costs. Total G&A expenses were $1,121,000 in 2003, and included a non-cash stock option expense of $87,000, reflecting the fair value of stock options granted to non-employees; an additional $204,000 was capitalized in 2003. In 2002, $954,000 (including stock options of $98,000) was expensed, while $87,000 was capitalized.

G&A expenses per boe declined 32 percent to $3.11 from $4.60 in 2002. Further reductions are likely in 2004 as production volumes expand.

INTEREST AND FOREIGN EXCHANGE

Throughout 2003 the company utilized available lines of bank credit to finance its increased activities. Accordingly, while interest rates continued at relatively low levels, total interest expense increased to $756,000 in 2003, compared to $137,000 reported last year. Unit costs rose to $2.10 per boe in 2003 compared to $0.66 per boe in 2002, as debt and related interest costs grew faster than production rates. Interest costs per boe are expected to be lower in 2004 with expected production increases. Management will utilize available banking facilities to leverage shareholders' capital in continuing to expand the company.

The impact of a fluctuating US dollar and Argentine peso relative to the Canadian dollar, when translating foreign denominated financial statements and operating results, was nominal in 2003 and 2002. The company's main exposure to foreign currency risk relates to pricing crude oil sales, which are denominated in US dollars. However, some of this risk has been mitigated by hedging a portion of the company's crude oil production in Canadian dollar denominated hedge contracts.

2003 Operating Netbacks by Country and Product

Per unit netbacks are calculated by dividing netbacks by sales volumes. Operating netbacks by product type and by country are indicated below.

	Canada						**Argentina**			
	Light oil		Heavy oil		Natural gas		Light oil		Natural gas	
	Total	Per bbl	Total	Per bbl	Total	Per mcf	Total	Per bbl	Total	Per mcf
Average daily production	**435 bbl/d**		**306 bbl/d**		**633 mcf/d**		**48 bbl/d**		**557 mcf/d**	
Oil and natural gas revenue	**$ 5,169,100**	**$ 32.56**	**$ 2,823,918**	**$ 25.28**	**$ 1,234,437**	**$ 5.34**	**$ 656,826**	**$ 37.49**	**$ 46,436**	**$ 0.23**
Royalties	(1,254,634)	(7.90)	(437,633)	(3.92)	(30,633)	(0.13)	(65,700)	(3.75)	(5,840)	(0.03)
Operating costs	(1,318,354)	(8.30)	(1,034,618)	(9.26)	(438,218)	(1.90)	(243,395)	(13.89)	(17,207)	(0.08)
Netback	**$ 2,596,112**	**$ 16.35**	**$ 1,351,667**	**$ 12.10**	**$ 765,586**	**$ 3.31**	**$ 347,731**	**$ 19.85**	**$ 23,389**	**$ 0.12**

DEPRECIATION, DEPLETION AND ABANDONMENT (DD&A)

The amount reported in 2003 for depletion and depreciation expense includes a provision for future well site restoration and abandonment costs of $281,000. The total 2003 DD&A provision of $3.6 million represents a 284 percent increase from 2002. This increase is directly related to the company's significantly increased Canadian production volumes and capital expenditures. A modest depletion expense was recognized for Argentinian operations, as its depletion base includes only $600,000 of 2002 and 2003 capital costs, as Argentinian oil and gas assets were written down to $1.00 in 2001. On a unit of production basis, DD&A per boe was $9.91 in 2003 and $4.48 in 2002. This reflects the conservative nature of new proved reserve estimates pursuant to NI 51-101 and not having the full impact of new production from 2003 investments until 2004.

CEILING TEST

Oil and gas companies are required to compare the recoverable value of their oil and gas assets to their recorded carrying value at the end of each reporting period (quarterly and annually), using commodity prices realized at the end of each period. Excess carrying values over ceiling value are to be written off against earnings. No writedown was required for any reporting period in 2003 or 2002.

INCOME TAXES

The provision for a current income tax recovery of $48,000 in 2003 represents taxes recoverable in Argentina; the charge of $63,000 in 2002 represents minimum cash income taxes payable in respect of the company's Argentinian branch operations for that year. Income earned in Canada will continue to be sheltered from Canadian income taxes until the company utilizes its approximately $52 million of deductible tax pools and operating loss carry forwards, which are supplemented by ongoing capital programs.

During 2002 and 2003, based on company performance and future prospects, the company recognized the benefit of its available income tax loss carry forwards and differences between the carrying value and tax basis of its property and equipment. A future income tax recovery of $4.5 million was recognized in 2003 and $483,000 was reported in 2002.

NET EARNINGS AND SHARES OUTSTANDING

For 2003, net earnings were $4.2 million or $0.13 per basic share and $0.12 per diluted share compared to earnings in 2002 of $501,000 or $0.03 per basic and diluted share. This represents an increase of 737 percent overall and 333 percent on a per basic share basis for 2003 over 2002.

Earnings per boe produced were $11.63 in 2003 compared to earnings of $2.42 per boe last year, reflecting a lower production base in 2002 and lower prices. There were no writedowns in 2002 or 2003.

For the year 2003, weighted average shares outstanding were 32,362,110 (2002–19,890,276) and weighted average diluted shares outstanding, as calculated by the treasury stock method, were 35,333,124 (2002 – 20,376,708).

As at March 26, 2004, the company had the following securities issued and outstanding:

- 46,093,425 common shares;
- 4,928,645 share purchase warrants; and
- 2,935,000 share purchase options.

Details of the exercise rights and terms of the warrants and options are noted in the Consolidated Financial Statements, included in this annual report.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations and cash flow per share do not have standardized meanings prescribed by generally accepted accounting principles and therefore may not be comparable to similar measures used by other companies. Nevertheless, Connacher's management uses cash flow from operations and cash flow per share as a performance measurement.

Cash flow from operations for 2003 was $3,353,000 ($0.10 per basic and diluted share) compared to $1,047,000 ($0.05 per basic and diluted share) in 2002. This significant improvement reflects increased production, higher prices in Canada and improved netbacks due to lower unit administrative costs, offset by higher royalties, operating costs and interest charges.

Cash flow per boe was $9.31 in 2003, compared to $5.05 in 2002, an 84 percent improvement. This represented 34 percent of selling price in 2003 compared to 24 percent in 2002.

While the company generated healthy cash flow in 2003, it also utilized equity financing, borrowings, cash balances and trade credit to fund its much expanded capital program in 2003.

Capital expenditures in 2003 totaled $35.8 million as follows:

- $10.8 million for oil and gas property acquisitions (Battrum and Steelman);
- $16.0 million for drilling, equipping, completing 57 net wells and for workovers;
- $4.6 million for production facilities at Cabri; and
- $4.4 million to acquire additional undeveloped acreage at Crown sale, seismic and administrative assets.

All but $500,000 of these expenditures were in Canada. In Argentina capital was primarily spent on a new exploratory well. The company's capital expenditures are generally discretionary and can be adjusted for drilling results or changes in cash flow regardless of the source of change, including variations in prices received for crude oil and natural gas sales. Certain of the company's expenditures are renounced to investors who acquire flow-through common shares. Generally such expenditures are exploratory in nature; this may influence expenditure types if such financing methods have been employed during a given year or period.

These 2003 expenditures were financed from operating cash flow ($3.4 million), new equity including proceeds from the exercise of share purchase warrants and stock options ($15.0 million), net new loans ($9.5 million) and trade credit ($8.3 million). Cash balances increased by $378,000 during the year. At December 31, 2003, Connacher's working capital deficit was $21.0 million, including bank loans of $12.1 million, which are now required to be reported as a current liability. At December 31, 2002 the company had $2.1 million of bank indebtedness and a $458,000 note

Net Earnings and Shares Outstanding

Operating Netbacks - Combined Canada and Argentina

	2003		2002		% Change	
	Total	Per boe	Total	Per boe	Total	Per boe
Operating Netback	**$ 5,136,059**	**$ 14.25**	$ 2,102,837	$ 10.15	144%	40%
General & Administrative	(1,121,279)	(3.11)	(954,271)	(4.60)	18%	(32%)
Interest	(755,566)	(2.10)	(136,778)	(0.66)	452%	218%
Foreign Exchange Loss	(45,190)	(0.12)	(1,881)	(0.01)	2,302%	1,100%
Depletion and depreciation	(3,571,891)	(9.91)	(929,265)	(4.48)	284%	121%
Taxes	4,548,183	12.62	420,078	2.02	983%	525%
Net Earnings	**$4,190,316**	**$11.63**	**$500,720**	**$2.42**	**737%**	**381%**

payable outstanding; and at December 31, 2001 it carried $175,000 of bank debt. Management is of the opinion its working capital deficit and bank loans were at manageable levels at year end having regard to its exit rate cash flow, unused available credit, expected production, expected cash flow from operations and expected scheduling of 2004 capital spending.

In 2003 Connacher completed two equity issues for net cash proceeds of $11.1 million after commissions, legal expenses, stock exchange fees and other issue expenses. Connacher also received $3.4 million from the exercise of outstanding warrants and stock options during the year.

Throughout 2003 the company's banker continuously expanded Connacher's credit facilities. As at December 31, 2003, the company had available a $21.5 million revolving line of credit (LOC) and a $10 million acquisition / development line of credit (AD Line), against which were drawn $12.1 million and nil, respectively. The company does not have capital lease obligations, any capital or purchase commitments or any other off-balance sheet debt. The company is not subject to any outstanding legal claims, nor any environmental or safety claims. All of its indebtedness and commitments are disclosed in the Consolidated Financial Statements included in the Annual Report.

During 2002, Connacher issued a $500,000 subordinated secured note as partial consideration for the purchase of a producing property. This note was partially repaid during 2002 and fully repaid in January, 2003.

During 2003, the company satisfied its commitment to spend the capital associated with its 2002 flow-through shares financing, as required by taxation authorities. The company has a commitment to incur $5 million of resource expenditures before December 31, 2004 related to the December 2003 financing.

The 2003 capital program including acquisitions added 4.2 million boe of total proved and probable reserves. All calculations hereafter refer to this category of reserves. Of these additions, 3 million boe were acquired for $10.8 million or $3.60 per boe, 1.2 million barrels were added through capital spending of $24.6 million for an F&D cost of $20.50 per boe and total FD&A costs were $10.82 per boe.

When incremental estimated future capital requirements of $9.8 million are added to actual 2003 outlays, F&D costs rise to $28.67 per boe while FD&A costs are $10.82 per boe. Connacher believes total FD&A costs (before and after estimated incremental future costs) are more representative amounts by which to evaluate the efficacy of the company's capital spending, as acquisitions have been and will continue to be an integral part of its growth strategy. Furthermore, F&D costs may be incurred for the longer term, may not result in immediate reserve recognition and in the company's opinion are best judged over a three or five year period, especially as there was a change in the reserve estimation methodology in 2003 which could make comparisons to prior periods somewhat misleading.

FD&A costs for 2002 and 2003 combined have averaged $7.84 per boe of total proved and probable reserve additions (proven plus one-half probable in 2002) although reserve evaluation methods changed in 2003. With future capital requirements of $11 million, FD&A costs for 2002 and 2003 combined were $9.79 per boe.

RELATED PARTY TRANSACTIONS

During 2003 and 2002 the company's President & Chief Executive Officer (CEO) and the company's Chief Operating Office (COO) provided their services to the company through their private management services companies. (During 2003 the COO became a salaried employee). A total of $167,200 (2002 - $275,500) was paid to the President & CEO and the COO for consulting services they provided to the company. Transactions with these parties occurred within the normal course of business, in amounts agreed by the parties. (Effective January 1, 2004, the President & CEO also became a salaried employee).

QUARTERLY RESULTS

Please see table on facing page.

ACCOUNTING ESTIMATES AND CHANGES IN ACCOUNTING POLICIES

In applying generally accepted accounting principles (GAAP), certain judgments, assumptions and estimates are required which could have a significant impact on financial results. The most significant estimates for the company are of its crude oil and natural gas reserves.

Capitalized costs are depleted, depreciated and amortized on a unit of production basis over the life of the oil and gas reserves; the carrying value of capitalized costs are compared to a recoverable ceiling value utilizing these reserve estimates; and provisions are made to account for future well site restoration and abandonment costs utilizing these reserve estimates. Reserve revisions could have a significant consequence to the determination of earnings. The reserve estimates used by Connacher have been evaluated and reported upon by experienced independent petroleum engineering consultants, in accordance with regulatory standards (NI 51-101).

There have been many recent changes made and proposed to Canadian and international accounting standards. In 2003, the company adopted new policies respecting hedge accounting, cash flow reporting, financial instruments recognition and measurement, disclosure of guarantees, impairment of long-lived assets and disposal of long-lived assets and discontinued operations. These recent changes have not impacted the company. The company is in the process of assessing the impact of proposed changes respecting accounting and disclosure of stock-based compensation, the new full cost method of oil and gas accounting, asset retirement obligations, and flow-through shares. Although the assessment is not complete, the company does not believe that the proposed changes will have a significant impact on its financial results.

OUTLOOK

The company's business plan for 2004 contemplates continued growth. To accomplish this, the company plans an active capital program on oil and gas property acquisition and development drilling, mostly in Canada.

Forecast operating cash flow, new bank borrowings and equity to be raised in 2004 will finance Connacher's planned 2004 capital spending program.

In November 2003, Connacher issued guidance for its anticipated operating and financial results for 2004. Events, including some beyond the company's control, have required the company to reduce its expectations and reassess and reschedule its planned capital program for 2004. The company has decided to discontinue the issuance of detailed guidance due to the difficulty in forecasting for a high growth company in a long-term business, when results could be significantly affected in the short term or quarter-to-quarter by drilling outcomes and timing.

All estimates and statements which have been issued with respect to 2004 guidance were or are forward-looking statements. This involves inherent risks and uncertainties where actual results will differ and such differences could be material. There can be no assurance Connacher will achieve the drilling results and levels of production it might assume in its 2004 plan or any versions thereof. In addition, oil and gas prices are subject to fluctuation and there can be no assurance that the prices assumed for the 2004 plan or any variation thereof will be attained.

BUSINESS RISKS

Connacher, being a junior oil and gas exploration, development and production company, is exposed to certain risks and uncertainties inherent in the oil and gas business. Furthermore, being a smaller independent company, it is exposed to financing and other risks which may impair its ability to realize on its assets or to capitalize on opportunities which might become available to it. Additionally, because the company operates in various jurisdictions, it may become exposed to other risks including currency fluctuations, political risk and varying forms of fiscal regimes or changes thereto which may impair its ability to conduct profitable operations. Connacher experienced these developments in Argentina in late 2001, 2002 and some continued into 2003.

The risks arising in the oil and gas industry include price fluctuations for both crude oil and natural gas over which the company has limited control; risks

arising from exploration and development activities; production risks associated with the depletion of reservoirs and the ability to market production. Additional risks include environmental and safety concerns.

As a relatively small concern, the company has to rely on access to capital markets for new equity to supplement internally generated cash flow and bank borrowings to finance its growth plans. Periodically, these markets may not be receptive to offerings of new equity from treasury, whether by way of private placement or public offerings. This may be further complicated by the limited market liquidity for shares of smaller companies, limiting access to institutional investors. An increased emphasis on flow-through share financings may accelerate the pace at which junior oil and gas companies become cash-taxable, which could reduce cash flow available for capital expenditures on growth projects. Periodic fluctuations in energy prices may also affect lending policies of the company's banker, whether for existing loans or new borrowings. This in turn could limit growth prospects over the short run or may even require the company to dedicate cash flow, dispose of properties or raise new equity to reduce bank borrowings under circumstances of declining energy prices or disappointing drilling results.

The success of the company's capital programs as embodied in its productivity and reserve base could also impact its prospective liquidity and pace of future activities. Control of finding, development, operating and overhead costs per boe is an important criterion in determining company growth, success and access to new capital sources.

The company attempts to mitigate its business and operational risk exposures by maintaining comprehensive insurance coverage on its assets and operations, by employing or contracting competent technicians and professionals, by instituting and maintaining operational health, safety and environmental standards and procedures and by maintaining a prudent approach to exploration and development activities. The company also addresses and regularly reports on the impact of risks to its shareholders, writing down the carrying values of assets that may not be recoverable.

Furthermore, the company generally relies on equity financing and a bias towards conservative financing of its operations under normal industry conditions to offset the inherent risks of domestic and international oil and gas exploration, development and production activities. The company has entered into forward sale, fixed price contracts to mitigate reduced product price risk and foreign exchange risk during periods of price improvement, primarily with a view to assuring the availability of funds for capital programs and to enhance the creditworthiness of its assets with its lenders. While hedging activities may have opportunity costs when realized prices exceed hedged pricing, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility.

	2002				**2003**			
Three Months Ended	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31
Financial Highlights								
($000 except per share amounts) - Unaudited								
Total Revenue, gross	679	917	1,075	1,655	2,164	2,474	2,491	2,853
Cash flow from operations (1)	60	257	234	496	779	821	745	1,008
Basic, per share (1)	-	0.02	0.01	0.02	0.03	0.02	0.02	0.03
Diluted, per share (1)	-	0.02	0.01	0.02	0.03	0.03	0.02	0.02
Net earnings	(127)	28	41	559	272	172	2,965	781
Basic, per share	-	-	-	0.03	0.01	0.01	0.08	0.03
Diluted, per share	-	-	-	0.03	0.01	0.01	0.07	0.03
Capital Spending	4,123	1,182	1,941	1,768	10,768	4,272	5,715	15,015
Bank debt	1,729	450	1,850	2,100	10,650	12,500	13,800	12,100
Working capital deficiency (surplus)	(313)	658	1,008	846	864	179	2,695	8,994
Note payable	494	477	465	458	-	-	-	-
Net debt	1,910	1,585	3,323	3,404	11,514	12,679	16,495	21,094
Shareholders' equity	2,613	3,560	3,228	5,279	7,447	9,718	13,613	24,486
Operating Highlights								
Production								
Natural gas (mcf/d)	1,340	1,536	1,123	1,462	1,216	1,033	1,012	1,496
Crude oil (bbl/d)	237	288	364	469	582	752	839	978
Equivalent (boe/d) (6:1)	460	544	551	713	785	924	1,008	1,228
Pricing								
Crude oil ($/bbl)	22.17	23.63	25.97	27.36	32.22	33.10	29.40	26.96
Natural gas ($/mcf)	1.65	2.09	1.93	3.29	4.03	2.18	2.35	3.02
Selected Highlights ($/boe)								
Weighted average sales price	16.38	18.51	21.20	25.24	30.15	29.37	26.84	25.17
Other income	0.16	0.10	0.11	0.49	0.50	0.04	0.03	0.10
Royalties, net of ARTC	2.17	2.17	3.21	3.62	5.78	5.20	5.08	4.23
Operating expenses	7.63	6.18	7.74	9.31	7.51	7.46	7.89	10.29
Netback	6.74	10.26	10.36	12.80	17.36	16.75	13.90	10.75
Common Share Information								
Shares outstanding at end of period (000)	17,971	21,671	21,671	24,175	28,717	34,082	36,512	45,903
Weighted average shares outstanding for the period								
Basic (000)	17,013	18,426	21,671	22,408	25,021	29,421	35,820	39,022
Diluted (000)	17,013	18,426	22,443	23,626	25,528	31,945	38,817	42,138
Volume traded during quarter (000)	106	231	191	418	6,031	8,342	10,027	15,045
Common share price ($)								
High	0.42	0.42	0.68	0.58	0.45	0.76	0.87	1.60
Low	0.20	0.26	0.25	0.32	0.31	0.40	0.65	0.74
Close (end of period)	0.38	0.35	0.50	0.43	0.42	0.71	0.75	1.60

(1) Cash flow from operations and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by others.

consolidated financial statements

MANAGEMENT'S REPORT

To the Shareholders of
Connacher Oil and Gas Limited:

The consolidated financial statements of Connacher Oil and Gas Limited were prepared by and are the responsibility of management. The statements have been prepared in conformity with Canadian generally accepted accounting principles appropriate in the circumstances and include some amounts that are based on management's best estimates and judgments.

The company maintains systems of internal accounting controls designed to provide reasonable assurance that all transactions are properly recorded in the company's books and records, that policies and procedures are adhered to and that the assets are protected from unauthorized use. The systems of internal accounting controls are complemented by the selection, training and development of professional managers.

The consolidated financial statements have been audited by the independent accounting firm Deloitte & Touche, LLP whose appointment is ratified yearly by the shareholders at the annual shareholders' meeting. The independent accountants perform such tests and related procedures as they deem necessary to arrive at an opinion on the fairness of the financial statements.

The audit committee of the board of directors periodically meets with the independent auditors and management to satisfy itself that it is properly discharging its responsibilities. The independent auditors have unrestricted access to the audit committee, without management present, to discuss the results of their examination and the quality of financial reporting and internal accounting control.

Signed,
"R. A. Gusella"
President and Chief Executive Officer
Connacher Oil and Gas Limited
March 26, 2004

Signed,
"R. R. Kines"
Chief Financial Officer
Connacher Oil and Gas Limited
March 26, 2004

AUDITORS' REPORT

To the Shareholders of
Connacher Oil and Gas Limited:

We have audited the consolidated balance sheets of Connacher Oil and Gas Limited as at December 31, 2003 and 2002 and the consolidated statements of operations and retained earnings and of cash flows for the years then ended. These consolidated financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Signed,
"DELOITTE & TOUCHE LLP"

Chartered Accountants

Calgary, Alberta
March 26, 2004

	2003 ($)	2002 ($)
ASSETS		
CURRENT		
Cash	627,302	248,949
Accounts Receivable	2,657,150	920,084
Loan receivable (Note 3)	135,848	140,820
Prepaid expenses	297,009	174,287
	3,717,309	1,484,140
Deposits (Note 4)	279,700	-
Property and equipment (Note 5)	41,269,748	8,770,741
Future income tax asset (Note 6)	4,402,320	-
	49,669,077	10,254,881
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	12,710,892	2,329,942
Bank loans (Note 7)	12,100,000	2,100,000
	24,810,892	4,429,942
Provision for future site restoration	372,644	87,797
Note payable	-	457,806
	372,644	545,603
SHAREHOLDERS' EQUITY		
Share capital and contributed surplus (Note 8)	19,794,505	4,778,616
Retained earnings	4,691,036	500,720
	24,485,541	5,279,336
	49,669,077	10,254,881

Commitments, contingencies and guarantees (Note 11)

Approved by the Board
(signed) "S.D. McGregor" Director
(signed) "G.W. Freeman" Director

	2003	2002
	($)	($)
REVENUE		
Petroleum and natural gas sales	9,930,717	4,276,480
Interest and other income	51,574	49,337
	9,982,291	4,325,817
Royalties	(1,794,441)	(597,634)
	8,187,850	3,728,183
EXPENSES		
Operating	3,051,791	1,625,346
General and administrative	1,121,279	954,271
Interest	755,566	136,778
Foreign exchange	45,190	1,881
Depletion and depreciation (Note 5)	3,571,891	929,265
	8,545,717	3,647,541
EARNINGS (LOSS) BEFORE TAXES	(357,867)	80,642
Current tax provision (recovery) (Note 6)	(48,183)	62,812
Future tax (recovery)	(4,500,000)	(482,890)
	(4,548,183)	(420,078)
NET EARNINGS	4,190,316	500,720
RETAINED EARNINGS, BEGINNING OF YEAR	500,720	-
RETAINED EARNINGS, END OF YEAR	4,691,036	500,720
EARNINGS PER SHARE		
Basic	0.13	0.03
Diluted	0.12	0.03
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING		
Basic	32,362,110	19,890,276
Diluted	35,333,124	20,376,708

	2003	2002
	($)	($)
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net earnings	**4,190,316**	500,720
Items not affecting cash:		
Depletion and depreciation	**3,571,891**	929,265
Stock-based compensation (Note 8e)	**87,000**	97,533
Future tax recovery	**(4,500,000)**	(482,890)
Foreign exchange - non-cash portion	**3,571**	1,881
Cash flow from operations	**3,352,778**	1,046,509
Changes in non-cash working capital	**8,526,133**	1,126,388
	11,878,911	2,172,897
FINANCING		
Issue of common shares, net of share issue costs	**15,026,569**	2,472,585
Increase in bank loans	**10,000,000**	1,925,000
Decrease in note payable	**(457,806)**	(42,194)
	24,568,763	4,355,391
INVESTING		
Acquisition and development of oil and gas properties (Note 5)	**(35,769,867)**	(7,013,865)
Well abandonment charges	**(19,754)**	(29,321)
Deposit on facilities (Note 4)	**(279,700)**	-
	(36,069,321)	(7,043,186)
NET INCREASE (DECREASE) IN CASH	**378,353**	(514,898)
CASH, BEGINNING OF YEAR	**248,949**	763,847
CASH, END OF YEAR	**627,302**	248,949
SUPPLEMENTARY INFORMATION - CASH PAYMENTS		
Interest	**755,566**	156,758
Income taxes	**14,092**	3,357

1. FINANCIAL STATEMENT PRESENTATION

The company is engaged in oil and gas exploration, development and production activities in Canada and in Argentina.

The consolidated financial statements include the accounts of the company and its wholly owned subsidiary company.

2. SIGNIFICANT ACCOUNTING POLICIES

Joint venture operations

A part of the company's activities are conducted with others, and these financial statements reflect only the company's proportionate interest in such activities.

Cash

Cash includes short-term deposits with maturities of three months or less.

Petroleum and natural gas operations

The company follows the full cost method of accounting whereby all costs relating to the exploration for and development of crude oil and natural gas reserves are capitalized on a country by country cost centre basis.

Capitalized costs of petroleum and natural gas properties and related equipment within a cost centre are depleted and depreciated using the unit-of-production method based on estimated proven crude oil and natural gas reserves as determined by independent consulting engineers. For the purpose of this calculation, production and reserves of natural gas are converted to equivalent units of crude oil based on relative energy content (6:1).

Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether or not proved reserves are attributable to the properties or impairment occurs. Gains or losses on sales of properties are recognized only when crediting the proceeds to cost would result in a change of 20 percent or more in the depletion and depreciation rate.

A ceiling test is applied quarterly to ensure the capitalized costs do not exceed the sum of estimated undiscounted unescalated future net revenues from proven reserves at period end prices plus unimpaired unproven property costs, less future development costs, related production, site restoration, interest and general and administrative costs, and applicable taxes. If capitalized costs are determined to be greater than the ceiling value, the excess is charged to operations. Unproved properties are evaluated separately for impairment based on assessment of future prospects.

Furniture and equipment

Furniture and equipment are recorded at cost and are being depreciated on a declining balance basis at rates of 20 percent to 30 percent per year.

Financial instruments

Financial instruments include accounts receivable, loan receivable, deposits, bank loans, accounts payable and accrued liabilities and the note payable. All carrying values of financial instruments approximate fair value unless otherwise noted.

Credit risk

The majority of the accounts receivable is in respect of oil and gas operations. The company generally extends unsecured credit to customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which credit has been extended. The company has not experienced any material credit loss in the collection of accounts receivable to date.

Commodity risk

The company periodically enters into forward fixed price contracts to reduce the exposure to commodity price fluctuations. Occasionally these contracts are denominated in Canadian dollars to mitigate foreign exchange risks.

Foreign currency translation

The company translates its foreign denominated monetary assets and liabilities at the exchange rate prevailing at year end. Non-monetary assets, liabilities and related depletion and depreciation are translated at historic rates. Revenues and expenses are translated at the average rate of exchange for the year. Any resulting foreign exchange gains or losses are included in operations.

Foreign operations

The company is exposed to risks from foreign exchange rates as it operates internationally and holds foreign denominated cash and short-term investments.

Provision for future site restoration

Estimates are made of the future site restoration and abandonment costs relating to the company's petroleum and natural gas properties at the end of their economic life, based on period end values, in accordance with current legislative requirements and industry practice. Charges are provided for on the unit-of-production basis and are recorded in the consolidated statement of operations as a component of depletion and depreciation and on the consolidated balance sheet as a long-term liability.

Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. Share capital is reduced and the future income tax asset is decreased by the tax related to the renounced expenditures at the time they are incurred.

Revenue recognition

Petroleum and natural gas sales are recognized as revenue at the time the respective commodities are delivered to purchasers. Gains and losses on forward fixed price commodity contracts are included in petroleum and natural gas sales revenue when the gain or loss occurs.

Stock-based compensation plan

From time to time, the company grants stock options as described in Note 8. No compensation expense is recognized when stock options are granted to employees or directors. Consideration paid by employees or directors on the exercise of stock options is credited to share capital.

Income taxes

The company follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributed to differences between the amounts reported in the financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding for the period. The company follows the treasury stock method to calculate diluted per share amounts. The treasury stock method assumes that any proceeds from the exercise of in-the-money stock options and other dilutive instruments would be used to purchase common shares at the average market price during the period.

3. LOAN RECEIVABLE

The loan receivable of $135,848 (US $87,000) is due from the operator of the Argentinean property concession in which the company holds a 50 percent interest. The loan is to be repaid from a portion of the operator's 50 percent share of the cash flow generated from production prior to December 31, 2004, is secured by an additional interest in the concession and bears interest at 6 percent per annum. During the year ended December 31, 2003 the operator repaid US $8,208 (2002 – US $34,200).

4. DEPOSITS – LONG TERM

In 2003 the company paid $360,000 to a pipeline transportation company for the construction of a natural gas pipeline. The company expects to be reimbursed for this cost over five years with the utilization of the pipeline. The current portion recoverable of $80,300 is included in prepaid expenses.

5. PROPERTY AND EQUIPMENT

	Cost $	Accumulated Depletion and Depreciation $	Net Book Value $
2003			
Petroleum and natural gas properties and equipment	**46,249,218**	**5,170,086**	**41,079,132**
Furniture and equipment	**305,504**	**114,888**	**190,616**
	46,554,722	**5,284,974**	**41,269,748**
2002			
Petroleum and natural gas properties and equipment	10,665,832	1,941,713	8,724,119
Furniture and equipment	99,267	52,645	46,622
	10,765,099	1,994,358	8,770,741

In 2003 the company purchased producing oil properties in the Battrum area of southwest Saskatchewan in two separate transactions from independent oil companies. On January 31, 2003, the company paid cash of $7.3 million to close an acquisition that had an effective acquisition date of December 1, 2002. On February 28, 2003 the company paid cash of $2.7 million to close an acquisition with an effective date of January 1, 2003. Both transactions were accounted for as of the closing dates.

During the year ended December 31, 2003, the company capitalized $204,300 of general and administrative expenses directly related to exploration and development activities (2002 –$86,837).

Unproved properties in the amount of $3,380,000 (2002 – $1,337,000) have been excluded from the computation of depletion and depreciation expense.

Depletion and depreciation expense includes a charge of $281,320 in respect of a provision for future well site restoration and abandonment costs (2002 - $92,607), based on total future estimated costs of $3,122,000 (2002 - $901,000).

The amount reported on the Consolidated Statements of Cash Flows for acquisitions in 2002 has been reduced by the amount of non-cash consideration paid to a vendor in the amount of $2 million. The value ascribed to the shares issued was based on the trading price of the company's shares at the time the transaction was announced (Note 8).

6. INCOME TAXES

The 2003 current income tax recovery of $48,183 is comprised of Argentine taxes recoverable. The 2002 tax provision of $62,812 is comprised of Argentine taxes.

The following table reconciles income taxes calculated at the Canadian statutory rate with actual income taxes:

	2003	2002
	$	$
Earnings (loss) before income taxes	**(357,867)**	80,642
Canadian statutory rate	**42.15%**	42.3%
Expected income taxes	**(150,840)**	34,112
Non-deductible Canadian crown payments	**551,500**	194,663
Canadian resource allowance	**(444,300)**	(191,870)
Benefit of tax deductions not previously recognized	**(4,796,860)**	(426,783)
Impact of reduction in Canadian tax rates	**340,500**	-
Foreign tax recovery	**(48,183)**	(30,200)
	(4,548,183)	(420,078)

At December 31, 2003 the company had the following deductible temporary differences:

	2003	2002
	$	$
Tax basis in excess of book value of property and equipment	**5,143,100**	7,323,100
Non-capital losses carried forward	**6,283,900**	4,015,600
Valuation allowance	**-**	(11,338,700)
	11,427,000	-

During 2003, based on company performance and future prospects, the company recognized the benefit of its available income tax losses carried forward and differences between the carrying value and tax basis of its property and equipment.

At December 31, 2003, the company had approximately $46 million of deductible tax pools in Canada.

Additionally, at December 31, 2003, the non-capital losses available to be carried forward for deduction against future taxable income expire as follows:

	$
2004	426,900
2005	522,100
2006	1,591,700
2007	130,200
2008	1,041,200
Thereafter	2,571,800
	6,283,900

7. BANK LOANS

As at December 31, 2003, the company had available a $21,500,000 Revolving Reducing Demand Loan ("Operating Line of Credit" or "LOC"). With scheduled reductions of $750,000 per month commencing the last day of January 2004, the LOC requires no additional principal repayments and bears interest at the bank's prime lending rate plus 3/8%. At December 31, 2003, the company had drawn $12,100,000 on this facility (2002 – $2,100,000). See note 12.

Additionally, the company had a $10,000,000 Non-Revolving Acquisition/ Development Demand Loan Facility. At December 31, 2003, the company had drawn nil (2002 – $900,000) on this facility. Interest is charged on borrowed amounts at prime plus ¾%.

These loans are secured by a $50,000,000 fixed and floating charge debenture and a general assignment of book debts.

The Canadian Institute of Chartered Accountants has issued an accounting pronouncement concerning the classification of debt that is effective for fiscal years commencing on or after January 1, 2002. Based on the pronouncement, all of the company's bank loans have been classified as a current liability since the lender has the right to require repayment within one year.

8. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized
The authorized share capital is comprised of the following:

Unlimited number of common voting shares
Unlimited number of first preferred shares
Unlimited number of second preferred shares

Issued
Only common shares have been issued by the company.

	Number of Shares	Amount $
Share Capital:		
Balance, December 31, 2001	14,220,879	1,212,774
Issued pursuant to property acquisition (Note 5)	3,750,000	1,500,000
Issued for cash by private placements (a)	6,811,472	2,775,626
Cancellation of escrowed shares (b)	(607,017)	-
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares (a)		(700,000)
Share issue costs		(347,541)
Tax effect of share issue costs		217,110
Interest on Share Purchase Loans (c)		(21,386)
Fair value of warrants issued (a)		44,500
Balance, December 31, 2002	24,175,334	4,681,083
Issued for cash by private placement (d)	13,407,955	12,320,700
Issued upon exercise of options (e)	534,000	133,000
Issued upon exercise of warrants (f)	7,785,636	3,236,114
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares (g)		(575,680)
Share issue costs		(1,194,630)
Tax effect of share issue costs		478,000
Repayment of share purchase loans and interest (c)		368,385
Fair value of warrants issued (d)		205,500
Warrants exercised (a), (d)		(36,300)
Balance, Share Capital, December 31, 2003	45,902,925	19,616,172
Contributed Surplus:		
Balance, December, 31, 2001		-
Fair value of share options granted (e)		97,533
Balance, December 31, 2002		97,533
Fair value of share options granted (e)		87,000
Share options exercised (e)		(6,200)
Balance, Contributed Surplus, December 31, 2003		178,333
Total Share Capital and Contributed Surplus:		
December 31, 2002		4,778,616
December 31, 2003		19,794,505

(a) Private Placements - 2002

Pursuant to flow-through share agreements dated June 2002, the company issued 2,500,000 common shares from treasury at a price of $0.40 per share and agreed to renounce resource expenditures of $1,000,000 by December 31, 2002. In 2002, the company incurred $1,000,000 of qualifying expenditures related to this renunciation and $675,700 with respect to flow-through shares issued in 2001.

In June 2002, the company issued 1,200,360 units, consisting of one common share and one half share purchase warrant, at a price of $0.35 per unit. Each whole share purchase warrant entitles the holder to purchase one additional common share from treasury at a price of $0.50 per share any time before June 20, 2004. For accounting purposes, a value of $36,500 was attributed to the issued warrants. As partial compensation for distributing the private placement, selling agents were issued 370,036 share purchase warrants on the same terms, but expiring June 20, 2003. For accounting purposes, a value of $8,000 was attributed to those issued warrants. In 2003, 154,750 of the investor warrants and all of the agent warrants were exercised.

Pursuant to flow-through share agreements dated November 2002, the company issued 3,111,112 common shares from treasury at a price of $0.45 per share and renounced resource expenditures of $1,400,000 on December 31, 2002. (Note 8 (g)).

(b) Cancellation of escrowed shares

In October 2002, escrowed shares conditionally issued in 1997 were cancelled as the conditions for their issuance were not met.

(c) Share Purchase Loans

Pursuant to a Loan and Share Pledge Agreement dated July 5, 2001, the company provided a loan to the Chief Executive Officer in the amount of $200,000. This amount was secured by one million common shares and one million common share purchase warrants of the company, bore interest at bank prime and was due on the earlier of July 5, 2004 or the date of the sale of the securities.

Pursuant to a Loan and Share Pledge Agreement dated August 31, 2001, the company provided a loan to the Chief Operating Officer in the amount of $147,000. This amount was secured by 700,000 common shares and 700,000 common share purchase warrants of the company, bore interest at bank prime and was due on the earlier of August 31, 2004 or the date of the sale of the securities.
In 2003 the share purchase loans including interest were repaid.

(d) Private Placements - 2003

In March 2003 the company issued 4,542,155 units, consisting of one common share and one share purchase warrant, at a price of $0.45 per unit. Each share purchase warrant entitles the holder to purchase one additional common share from treasury at a price of $0.50 per share any time before February 28, 2005. For accounting purposes, a value of $143,500 has been ascribed to the issued warrants. As partial compensation for distributing the private placement, selling agents were issued 227,107 share purchase warrants on the same terms. For accounting purposes, a value of $10,500 was assigned to those issued warrants. In 2003, 473,000 of the investor warrants and 87,850 agent warrants were exercised.

In December 2003 the company issued from treasury 5,162,000 common shares at $1.05 per share and 3,703,800 flow-through common shares at $1.35 per share, renouncing resource expenditures of $5,000,130 effective December 31, 2003. As partial compensation for distributing the shares, selling agents were issued 310,303 share purchase warrants, each warrant entitling the holder to acquire one common share from treasury at a price of $1.18 anytime before December 10, 2004. For accounting purposes, a value of $51,500 was assigned to those issued warrants; none have been exercised.

(e) Stock Options

A summary of the company's outstanding stock option grants, as at December 31, 2003 and 2002 and changes during those years is presented below:

	2003		2002	
	Number of Shares	**Weighted Average Exercise Price**	Number of Shares	Weighted Average Exercise Price
		$		$
Outstanding, beginning of year	**2,324,000**	**0.31**	1,016,500	0.34
Granted	**1,040,000**	**0.65**	1,500,000	0.36
Expired	**-**	**-**	(192,500)	(0.87)
Exercised	**(534,000)**	**(0.24)**	-	-
Outstanding, end of year	**2,830,000**	**0.45**	2,324,000	0.31

All options have been granted for a period of five years and were fully vested and exercisable at December 31, 2003 as described in the table below. No additional options were reserved for issuance.

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life (Years)
$0.20 - $0.30	1,035,000	2.7
$0.31 - $0.50	1,095,000	3.8
$0.51 - $0.75	700,000	4.6
	2,830,000	

In 2003 a compensatory non-cash expense of $87,000 (2002 - $97,533) was recorded in general and administrative expenses, reflecting the fair value of share options granted during the year to non-employees.

The company does not record compensation expense in the consolidated financial statements for stock options granted at market values to employees and directors. The following table provides pro forma measures of net earnings and net earnings per common share had such compensation expense been recognized for stock options granted to employees and directors based on fair values at the date of grant.

	Year ended December 31, 2003		Year ended December 31, 2002	
	As Reported	**Pro Forma**	As Reported	Pro Forma
	$	**$**	$	$
Net earnings	**4,190,316**	**4,033,520**	500,720	441,611
Per share				
Basic	**0.13**	**0.12**	0.03	0.02
Diluted	**0.12**	**0.11**	0.03	0.02

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

	2003	2002
Risk free interest rate	**3.0%**	3.5%
Expected option life (years)	**3**	5
Expected volatility	**53%**	40%

The weighted average fair value at the date of grant of options granted to employees and directors in 2003 was $0.22 per option (2002 - $0.11).

(f) Share purchase warrants

A summary of the company's outstanding share purchase warrants, as at December 31, 2003 and 2002 and changes during the years is presented below:

	2003	2002
Outstanding, beginning of year	**7,670,216**	6,700,000
Issued in the year	**5,099,565**	970,216
Exercised in the year	**(7,785,636)**	-
Outstanding, end of year	**4,984,145**	7,670,216

The 4,984,145 warrants outstanding are exercisable to purchase common shares from treasury as follows:

(i) 445,430 common shares at $0.50 per share until their expiry on June 20, 2004;
(ii) 310,303 common shares at $1.18 per share until their expiry on December 9, 2004; and
(iii) 4,228,412 common shares at $0.50 per share until their expiry on February 28, 2005.

(g) In 2003, the company incurred all of its $1.4 million resource expenditure commitment related to its flow through shares issued in 2002 and recognized the tax effect of these expenditures. The company has a further commitment to incur $5 million of resource expenditures before December 31, 2004 related to the December 9, 2003 financing.

(h) Per share amounts

The calculation of weighted average diluted shares outstanding includes the impact of most of the outstanding options and warrants.

9. SEGMENTED INFORMATION

The company has operations in Canada and Argentina; all operating activities are related to exploration, development and production of petroleum and natural gas.

	Canada $	Argentina $	Total $
2003			
Revenue, gross	**9,273,279**	**709,012**	**9,982,291**
Net earnings	**3,975,859**	**214,457**	**4,190,316**
Property and equipment	**40,706,791**	**562,957**	**41,269,748**
Capital expenditures	**35,204,272**	**565,595**	**35,769,867**
Total assets	**48,721,216**	**947,861**	**49,669,077**
2002			
Revenue, gross	3,666,599	659,218	4,325,817
Net earnings	343,727	156,993	500,720
Property and equipment	8,736,517	34,224	8,770,741
Capital expenditures	6,984,462	29,403	7,013,865
Total assets	9,741,541	513,340	10,254,881

10. RELATED PARTY TRANSACTIONS

The company paid the following amounts to companies in which officers of the company are related parties:

	2003 **$**	2002 $
Consulting fees	**167,200**	275,500

Transactions with the foregoing related parties occurred within the normal course of business and have been measured at their exchange amount. The exchange amount is the amount of consideration established and agreed to by the related parties.

11. COMMITMENTS, CONTINGENCIES AND GUARANTEES

The company has entered into crude oil sales agreements with an independent integrated oil company as follows:

- 250 bbl/d heavy crude oil production at Cdn. $30.83 (which is after deduction for crude oil price differentials) from March 1, 2003 to February 28, 2004 (Note 12), and
- 250 bbl/d medium gravity crude oil production based on a WTI reference price of Cdn. $45.60 per barrel (which is before deduction for crude oil price differentials) from April 1, 2003 to March 31, 2004. (Note 12)

The company's annual commitments under leases for office premises and operating costs, field compression equipment, software license agreements and other equipment are as follows:
2004 - $1,237,600; 2005 - $1,118,500; 2006 - $1,105,800; 2007 - $1,085,600; 2008 - $1,078,800.

Additionally, the company has various guarantees and indemnifications in place in the ordinary course of business, none of which are expected to have a significant impact on the company's financial statements or operations.

12. SUBSEQUENT EVENTS

In February 2004 the company renewed the crude oil sales agreement that expired February 28, 2004 on the following terms: 200 bbl/d heavy crude oil production at Cdn $42.67 (before deduction for crude oil price differential) from March 1, 2004 to February 28, 2005.

In March 2004 the company renewed the crude oil sales agreement that expired March 31, 2004 on the following terms: 250 bbl/d medium gravity crude oil production at Cdn $44.08 (before deduction for crude oil price differential) from April 1, 2004 to March 31, 2005.

In 2004, the company's banker agreed to eliminate the scheduled monthly reductions of $750,000 to its Operating Line of Credit for the months of February, March and April 2004. No other terms of the lending agreement have changed.

three year historical summary

	2003	2002	2001
FINANCIAL HIGHLIGHTS			
($000 except per share amounts) - Unaudited			
Total Revenue	**9,982**	4,326	1,129
Cash flow from operations (1)	**3,353**	1,047	(152)
Basic, per share (1)	**0.10**	0.05	(0.02)
Diluted, per share (1)	**0.10**	0.05	(0.02)
Net earnings	**4,190**	501	(1,214)
Basic, per share	**0.13**	0.03	(0.16)
Diluted, per share	**0.12**	0.03	(0.16)
Capital Spending	**35,770**	9,014	988
Bank debt	**12,100**	2,100	175
Working capital deficiency (surplus)	**8,994**	846	(829)
Note payable	**-**	458	-
Net debt	**21,094**	3,404	(654)
Shareholders' equity	**24,486**	5,279	1,213
Total Assets	**49,669**	10,255	1,706
OPERATING HIGHLIGHTS			
Production			
Natural gas (mcf/d)	**1,190**	1,365	624
Crude oil (bbl/d)	**789**	340	57
Equivalent (boe/d)	**987**	568	161
Pricing			
Crude Oil ($/bbl)	**30.03**	25.30	31.11
Natural gas ($/mcf)	**2.95**	2.28	2.09
Selected Highlights ($/boe)			
Weighted average sales price	**27.56**	20.64	19.12
Royalties, net of ARTC	**4.98**	2.88	3.27
Operating expenses	**8.47**	7.85	10.25
Netback	**14.25**	10.15	5.69
Reserves (boe) (2)			
Proved	**3,085**	1,513	420
Probable	**2,489**	249	75
Total	**5,574**	1,762	495
COMMON SHARE INFORMATION			
Shares outstanding at end of period (000)	**45,903**	24,175	14,221
Weighted average shares outstanding for the period			
Basic (000)	**32,362**	19,890	7,418
Diluted (000)	**35,333**	20,377	7,418
Volume traded during the year (000)	**39,445**	946	241
Common share price ($)			
High	**1.60**	0.68	0.35
Low	**0.30**	0.20	0.17
Close, end of year	**1.60**	0.43	0.27

(1) Cash flow from operations and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by others.
(2) Established reserves in 2001 and 2002.

abbreviations

ARTC
Alberta Royalty Tax Credit

bbls
barrels

bbl/d
barrels per day

bcf
billion cubic feet

boe
barrels of oil equivalent

boe/d
barrels of oil equivalent per day

DCF
discounted cash flow

GJ
gigajoule

mbbls
thousand barrels

mboe
thousand barrels of oil equivalent

mcf
thousand cubic feet

mcf/d
thousand cubic feet per day

mmbbls
million barrels

mmboe
million barrels of oil equivalent

mmcf
million cubic feet

mmcf/d
million cubic feet per day

NGLs
natural gas liquids

PV
present value

WI
working interest

WTI
West Texas Intermediate

corporate information

officers and management

Richard A. Gusella
President and Chief Executive Officer

Peter D. Sametz
Vice President, Operations

Richard R. Kines
Chief Financial Officer

Timothy J. O'Rourke
General Manager, Production

Songning Shen
Exploration Manager

Jennifer K. Kennedy
Secretary
Partner, Macleod Dixon LLP

board of directors

Richard A. Gusella
President and Chief Executive Officer
Connacher Oil and Gas Limited, Calgary

Charles W. Berard (2,3)
Chairman, Governance Committee
Partner, Macleod Dixon LLP, Calgary

Donald D. Copeland (1,2,3,4)
Chairman of the Board
President, Diamond Tree Resources Ltd., Calgary

Colin M. Evans (1,5)
President, Evans & Co. Inc., Calgary

Gary W. Freeman (1,3)
Chairman, Human Resources Committee
Co-founder and Director, Spirit Energy, Calgary

Stewart D. McGregor (1,2)
Chairman, Audit Committee
President, Camun Consulting Ltd.

(1) Audit committee
(2) Governance committee
(3) Human Resources Committee
(4) Resigned effective March 31, 2004
(5) Appointed April 5, 2004

auditors
Deloitte & Touche LLP, Calgary

bankers
National Bank of Canada, Calgary

solicitors
Macleod Dixon, LLP, Calgary

reservoir engineers
Outtrim Szabo Associates Ltd., Calgary

registrar and transfer agent
Valiant Trust Company, Calgary
Equity Transfer Services Inc., Toronto

stock exchange listing
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